DRAFT

PERMIT to OPERATE 9106-R6

and

PART 70 OPERATING PERMIT 9106

PLATFORM IRENE

PARCEL OCS-P-0441
POINT PEDERNALES UNIT
SANTA BARBARA COUNTY, CALIFORNIA
OUTER CONTINENTAL SHELF

<u>OWNER/OPERATOR</u>

Plains Exploration & Production Company

Santa Barbara County
Air Pollution Control District

December 2012

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
API	American Petroleum Institute
ASTM	American Society for Testing Materials
BACT	Best Available Control Technology
bpd	barrels per day (1 barrel = 42 gallons)
BOEM	Bureau of Ocean Energy Management
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring
District	Santa Barbara County Air Pollution Control (District)
dscf	dry standard cubic foot
EU	emission unit
°F	degree Fahrenheit
gal	gallon
gr	grain
HAP	hazardous air pollutant (as defined by CAAA, Section 112(b))
H_2S	hydrogen sulfide
I&M	inspection & maintenance
k	kilo (thousand)
l	liter
lb	pound
lbs/day	pounds per day
lbs/hr	pounds per hour
LACT	Lease Automatic Custody Transfer
LPG	liquid petroleum gas
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NEI	net emissions increase
NG	natural gas
NSPS	New Source Performance Standards
O2	oxygen
OCS	outer continental shelf
ppm(vd or w)	parts per million (volume dry or weight)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PRD	pressure relief device
PTO	Permit to Operate
RACT	Reasonably Available Control Technology
ROC	reactive organic compounds, same as "VOC" as used in this permit
RVP	Reid vapor pressure
scf	standard cubic foot
scfd (or scfm)	standard cubic feet per day (or per minute)
SIP	State Implementation Plan
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
THC	Total hydrocarbons
tpy, TPY	tons per year
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency
VE	visible emissions
VRS	vapor recovery system

1.0 Introduction

1.1 Purpose

General. The Santa Barbara County Air Pollution Control District (District) is responsible for implementing all applicable federal, state and local air pollution requirements that affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 55, 61, 63, 68, 70 and 82. The State regulations may be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable local regulations can be found in the District's Rules and Regulations.

Santa Barbara County is designated as an ozone non-attainment area for the state ambient air quality standards. The County is also designated a non-attainment area for the state PM_{10} ambient air quality standard.

Part 70 Permitting. This is a combined permitting action that covers both the Federal Part 70 permit *(Part 70 Operating Permit No. 9106)* as well as the State Operating Permit *(Permit to Operate No. 9106)*. The initial Part 70 permit for Platform Irene was issued October 17, 2000 in accordance with the requirements of the District's Part 70 operating permit program. This is the third renewal of the Part 70 permit and may include additional applicable requirements and associated compliance assurance conditions. Also, this permit incorporates any Part 70 minor modifications since the last renewal, and is being issued as a combined Part 70 and District reevaluation permit..

Platform Irene is part of the Plains Exploration & Production Co. (PXP) Lompoc/Point Pedernales stationary source (SSID=4632), which is a major source for VOC[1] and NO_x. This stationary source consists of the following facilities: Platform Irene, the Lompoc Oil and Gas Plant and the Lompoc Oil Field.

Conditions listed in this permit are based on federal, state or local rules and requirements. Sections 9.A, 9.B and 9.C of this permit are enforceable by the District, the USEPA and the public since these sections are federally enforceable under Part 70. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable.

Pursuant to the stated aims of Title V of the CAAA of 1990 (i.e., the Part 70 operating permit program), this permit has been designed to meet two objectives. First, compliance with all conditions in this permit would ensure compliance with all federally-enforceable requirements for the facility. Second, the permit would be a comprehensive document to be used as a reference by the permittee, the regulatory agencies and the public to assess compliance.

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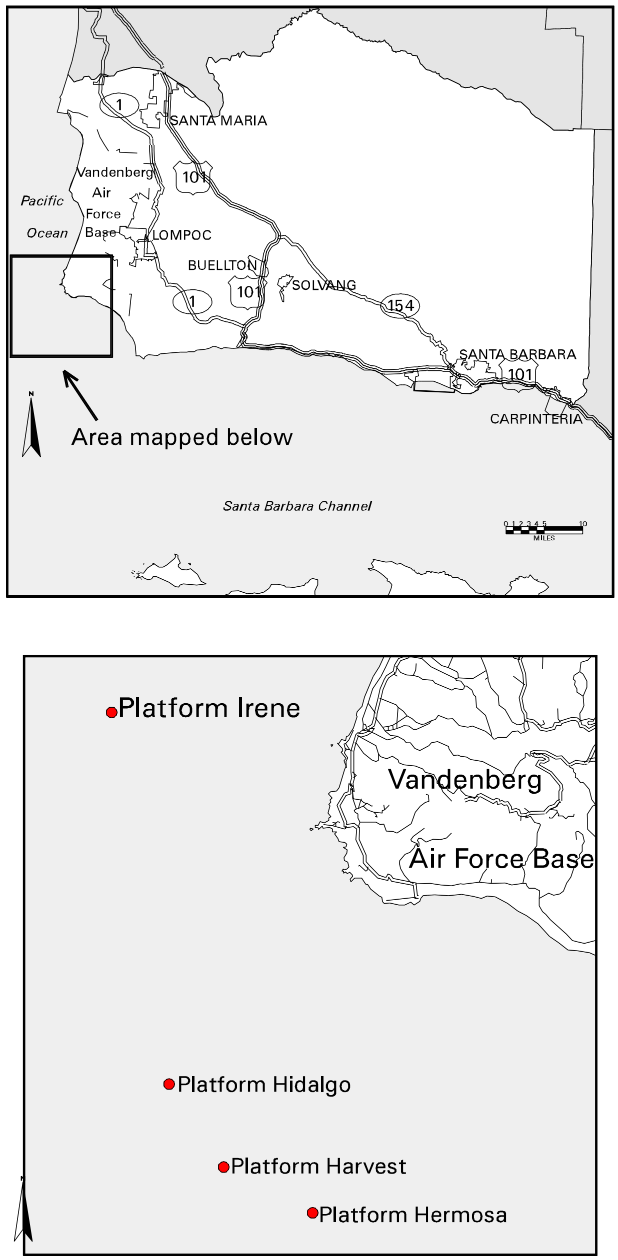
[1] VOC as defined in Regulation XIII has the same meaning as reactive organic compounds as defined in Rule 102. The term ROC shall be used throughout the remainder of this document, but where used in the context of the Part 70 regulation, the reader shall interpret the term as VOC.

Tailoring Rule. This reevaluation incorporates greenhouse gas emission calculations for the stationary source. On January 20, 2011, the District revised Rule 1301 to include greenhouse gases (GHGs) that are "subject to regulation" in the definition of "Regulated Air Pollutants". District Part 70 operating permits are being updated to incorporate the revised definition.

Figure 1.1   Location Map for Platform Irene



1.2 Facility Overview

1.2.1 Facility Overview: PXP is owner and operator of Platform Irene, located on offshore lease tract OCS-P-0441, approximately four miles west of Point Pedernales (Latitude 34° 36' 37.411" No., Longitude 120° 43' 45.744" West). The platform is situated in the Northern Zone of Santa Barbara County[2]. Figure 1.1 shows the relative location of the facility within the county. Platform Irene (FID #8016), an eight leg, seventy-two well slot platform, was installed in a water depth of 242 feet in 1985. Drilling operations began in 1986. Platform Irene produces crude oil and sour natural gas that is transported via subsea pipelines to PXP's Lompoc Oil and Gas Plant (LOGP) located approximately three miles north of Lompoc, CA. The oil emulsion is shipped via a 20" pipeline and the produced gas, dehydrated and compressed on Platform Irene, and shipped via an 8" subsea pipeline. The average gravity of the produced crude oil is 13.5° API. The design platform production rate is 150,000 barrels of wet oil per day (36,000 barrels of dry crude oil per day) and 12 million standard cubic feet of produced gas per day.

Platform Irene consists of the following systems:

- Production wellhead and subsurface system
- Well cleanup system
- Test separation system
- Oil shipping, metering, and pipeline system
- Produced water system
- Low pressure compression system
- Gas compression system
- Gas shipping and metering system
- Electrical system
- Safety system

The oil and gas undergo initial separation to reduce water and sediment content prior to being shipped to the LOGP facility. All equipment on Platform Irene, except the two pedestal cranes, emergency generators and water pump are powered by the PG&E electric grid provided through a subsea cable from shore.

The *PXP Lompoc/Point Pedernales Stationary Source* (SSID 4632) consists of the following facilities:

• La Purisima Lease	(FID 3069)
• Lompoc Oil and Gas Plant	(FID 3095)
• Jesus Maria "D" Lease	(FID 3309)
• Orcutt Fee	(FID 3310)
• Eefson Lease	(FID 3802)
• Jesus Maria "A" Lease	(FID 3832)
• Lompoc Fee	(FID 3837)
• Hill Lease	(FID 3839)
• Arkley Fee	(FID 4117)

[2] District Rule 102, Definition: "Northern Zone"

- Lompoc Internal Combustion Engines (FID 4218)
- Platform Irene (FID 8016)

1.2.2 Facility Permitting History: The following is the permit history for this facility:

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
PTO Mod 09106 01	09/04/1994	See Permit
PTO 09106	09/04/1994	Primary operating permit for Platform Irene.
ATC 09612	08/20/1997	Modification to PTO 9106 to reconcile changes made in PTO 6708-05 that impact PTO 9106.
Exempt 10027	11/11/1998	Exemption for hydroblasting equipment.
ATC/PTO 10086	06/24/1999	Replace supply boat. Revise fugitive I&M emission factors.
ATC 10307	10/16/2000	Installing covers on tanks 530 and 540.
PT-70/Reeval 09106 R2	10/17/2000	Pt70 PTO.
Trn O/O 09106 02	02/27/2001	Transfer of operatorship from Torch to Nuevo
PTO Mod 09106 04	04/12/2001	Minor mod 10401R to modify Pt-70 9106 restriction to complete installation of tank covers by the SCDP expiration date of ATC 10307.
PTO 10307	06/27/2001	Installing covers on tanks 530 and 540. See also Pt-70 No. 10438.
ATC/PTO 10776	12/20/2001	Pipeline H2S Increase. (Pt70 10777)
ATC/PTO 10776	02/20/2002	Pipeline H2S Increase. (Pt70 10777)
PTO Mod 09106 05	08/20/2002	MOB. Combined with PT70R 10832.
PT-70/Reeval 09106 R3	12/17/2003	Pt70 PTO.
Trn O/O 09106 03	09/23/2004	Transfer of Owner/Operator from Nuevo to Plains Exploration & Production.
Exempt 11325	10/26/2004	Platform Irene 8" produced water line repair.
ATC/PTO 11435	03/30/2005	ATC/PTO application for NOx emission limit changes for Supply Boat
PT-70 R 11436	03/30/2005	See ATC/PTO 11435
PTO Mod 09106 06	02/27/2006	Add additional supply boat (Victory Seahorse) to PTO 9106.
ATC/PTO 12006	03/31/2006	Increase the pilot fuel rate.
PTO 11922	06/22/2006	DICE permits due to loss of exemption. One FW pump engine CAT 3406DI at 420 bhp and one ES generator CAT 3408DI at 590 bhp.
PT-70 R 11923	06/22/2006	DICE permits due to loss of exemption. One FW pump engine CAT 3406DI at 420 bhp and one ES generator CAT 3408DI at 590 bhp. See PTO 11922
PTO 12012	07/05/2006	Adding 2 drilling generator IC engines to PTO 9106. This application was submitted subsequent to submittal of PTO 11922 (Irene DICE for ES Gen/FW Pump). PTO 11922 was issued on June 22, 2006 and included these generators.
PT-70/Reeval	12/08/2006	Pt70 permit renewal.

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
09106 R4		
ATC 12683	07/11/2008	Installation of a freewater knockout vessel.
Exempt 13026	01/26/2009	Specialty equipment exemption request per Rule 202F.5. Leap frog crane, CAT 3406 non-certified EPA engine. NOx emissions est'd 0.30 tons.
ATC/PTO 12965	01/30/2009	Replace two vessels
ATC/PTO 13044	03/06/2009	Replace three gas coolers.
PTO Mod 09106 08	04/17/2009	Permanently remove the requirement for the pipeline H2S monitor.
ATC Mod 12683 01	07/28/2009	Extend ATC 12683.
PT-70/Reeval 09106 R5	12/23/2009	Pt70 permit renewal.
ATC/PTO 13597	01/28/2011	Replacement of one glycol contactor and one compressor discharge scrubber.
ATC/PTO 13721	08/12/2011	Replacement of the existing platform combustion flare. No changes to allowed flare volumes or emissions occur with this project.
ATC/PTO 13733	08/30/2011	Change operating parameters for the flare pilot to propane on a continual basis.
PTO 12683	11/04/2011	
ATC 13694	01/05/2012	Installation of a vapor recovery unit.
ATC/PTO 13792	03/19/2012	Change operating parameters for the flare pilot and purge.

1.3 Emission Sources

Air pollution emissions from Platform Irene are the result of combustion sources, storage tanks and piping components such as valves and flanges. Section 4 of the permit provides the District's engineering analysis of these emission sources. Section 5 of the permit describes the allowable emissions from each permitted emissions unit, total platform emissions, and also lists the potential emissions from non-permitted emission units.

The emission sources include:

1. Supply boats used for transporting equipment, fuel, and supplies to and from the platform.
2. Helicopters for transportation of platform personnel.
3. Two diesel-fired pedestal cranes.
4. One diesel-fired production emergency generator.
5. Two diesel-fired drilling rig emergency generators.
6. One diesel-fired emergency fire water pump.
7. Piping components, produced water tanks, and other evaporative sources that release fugitive hydrocarbons into the atmosphere.
8. Fugitive hydrocarbons that are emitted into the atmosphere from solvent use.
9. Flare relief system to combust hydrocarbon gases.

A list of all permitted equipment is provided in Section 10.3.

1.4 Emission Control Overview

Air quality emission controls are utilized on Platform Irene for a number of emission units to reduce air pollution emissions. Additionally, the use of onshore utility grid power allows Platform Irene to operate without large gas turbine-powered generators or compressors. The emission controls employed on the platform include:

- A Fugitive Hydrocarbon Inspection & Maintenance (I&M) program for detecting and repairing leaks of hydrocarbons from piping components, consistent with the requirements of Rule 331 to reduce ROC emissions by approximately 80 percent.
- The supply boat main engines are optimized for low NO_x emissions through the use of Dual Advanced Diesel Engine Management (ADEMII) modules with electronically controlled unit injectors as well as dual turbochargers and a separate circuit aftercooler core.
- Use of Type "B" diesel fuel injectors on the pedestal crane engines to achieve NO_x emissions of 8.4 g/bhp-hr, consistent with Rule 333.
- Use of an amine-based scrubber to reduce the hydrogen sulfide content of produced gases which are periodically flared and from continuous purge and pilot combustion to meet the north county total sulfur limit of 796 ppmvd.

1.5 Offsets/Emission Reduction Credit Overview

The OCS air regulation, 40 C.F.R. Part 55, did not require existing sources to provide emission offsets however, permitting of the onshore processing facilities required PXP to offset emissions associated with onshore facility as well as the emissions generated by Platform Irene. Section 7 provides a detailed discussion of these offsets.

1.6 Part 70 Operating Permit Overview

1.6.1 Federally-enforceable Requirements: All federally enforceable requirements are listed in 40 CFR Part 70.2 (*Definitions*) under “applicable requirements.” These include all SIP-approved District Rules, all conditions in the District-issued Authority to Construct permits, and all conditions applicable to major sources under federally promulgated rules and regulations. All permits (and conditions therein) issued pursuant to the OCS Air Regulation are federally enforceable. All these requirements are enforceable by the public under CAAA. (*see Tables 3.1 and 3.2 for a list of federally enforceable requirements)*

1.6.2 Insignificant Emissions Units: Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit’s potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit’s potential to emit. Insignificant activities were listed in the Part 70 permit renewal application with supporting calculations. Applicable requirements may apply to insignificant units.

1.6.3 Federal Potential to Emit: The federal potential to emit (PTE) of a stationary source does not include fugitive emissions of any pollutant, unless the source is: (1) subject to a federal NSPS/NESHAP requirement which was in effect as of August 7, 1980, or (2) included in the 29-category source list specified in 40 CFR 51.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. (*See Section 5.4 for the federal PTE for this source)*

1.6.4 Permit Shield: The operator of a major source may be granted a shield: (a) specifically stipulating any federally-enforceable conditions that are no longer applicable to the source and (b) stating the reasons for such non-applicability. The permit shield must be based on a request from the source and its detailed review by the District. Permit shields cannot be indiscriminately granted with respect to all federal requirements. PXP made no request for a permit shield.

1.6.5 Alternate Operating Scenarios: A major source may be permitted to operate under different operating scenarios if appropriate descriptions of such scenarios are included in its Part 70 permit application and if such operations are allowed under federally-enforceable rules. PXP made no request for permitted alternative operating scenarios.

1.6.6 Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally-enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application; and, be re-submitted annually on the anniversary date of the permit or on a more frequent schedule specified in the permit. A "responsible official" of the owner/operator company signs each certification whose name and address is listed prominently in the Part 70 permit. *(see Section 1.6.9 below)*

1.6.7 Permit Reopening: Part 70 permits are re-opened and revised if the source becomes subject to a new rule or new permit conditions are necessary to ensure compliance with existing rules. The permits are also re-opened if they contain a material mistake or the emission limitations or other conditions are based on inaccurate permit application data.

1.6.8 Hazardous Air Pollutants (HAPs): Part 70 permits regulate emissions of HAPs from major sources through the imposition of maximum achievable control technology (MACT), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any other rule applicability.

1.6.9 Responsible Official: The designated responsible official and his mailing address is:

Mr. Thomas Goeres, Operations Manager
Plains Exploration & Production Company
201 South Broadway
Orcutt, California 93455

2.0 Process Description

2.1 Process Summary

2.1.1 *Production*: Platform Irene contains two identical well rooms. Each well room has the capacity to handle the production from 36 wells, giving the platform a 72-well total capacity. There are 24 sub-headers per well room. They are divided into four functional groups, each serving six wells. First, is the gas lift sub-header which supplies each well with dehydrated natural gas for gas lift. Second, is the test oil sub-header, which is used to place any individual well in test. From the test oil sub-header, oil is directed to a test oil header which in turn directs the oil to a test separator or to the well clean tank (V-180). Third, is the oil gathering sub-header which directs the oil to an oil gathering header which in turn directs oil to the free water knockout vessel then to the gross separator. Finally, there is a test gas sub-header which may be used when there is a switch from gas lift to electric submersible pumps.

Primary oil/water emulsion and gas separation occurs on Platform Irene. The gas is shipped to the Lompoc Oil and Gas Plant (LOGP) via an 8-inch pipeline and crude oil emulsion through a 20-inch pipeline. The process stream composition of the crude handling system on Platform Irene is primarily heavy liquid crude oil. Liquids released to the pressure drain and deck drain are returned to the shipping tank and transported to the LOGP for processing. The design rate for the platform is 150,000 barrels of oil emulsion per day (bpd), 36,000 bpd of dry crude oil and four million cubic feet per day of produced gas. Produced water, which is separated from the crude, is treated and may be either shipped via a 8-inch pipeline back to Platform Irene for disposal, or disposed of in injection wells at the Lompoc oil field.

There are two types of drain systems on Platform Irene. The first is a pressure drain system. This system accepts liquids from an oil relief line in the sub-header. These are joined by liquids in a pressure drain line and sent to the production drains receiver (V-910). The pressure drain line receives relief liquids from the test separators, gross separators, shipping tank, shipping pumps, suction scrubber, inter-stage scrubber, discharge scrubber and from the flare scrubber. The production drains receiver also receives liquids from the oil pig launcher, gas pig launcher and from the water launcher/receiver. Once in the production drains receiver, liquids go to one of two production drain pumps (P-920 A or B). There it joins liquids from the waste water tanks, which are all sent to the shipping tank.

In addition to the pressure drain system, there is a non-pressurized deck drain system. All of the decks have curbs around the perimeter, and curbs or seals around all deck penetrations, to prevent any fluids from spilling overboard.

Any liquid spilled on the sub-deck, drains into three small sumps (S-500 A, B, or C) in the decking. Two sumps have a small pump skid containing two pumps, one electric centrifugal pump (P-510 A or B) and one air powered diaphragm pump (P-520 A or B). The third sump has only one air powered diaphragm pump (P-520 C). Liquids from the sub-deck sumps are pumped into tank T-530.

Deck drains in the production deck gravity feed to V-910. The drill deck and sub-deck are all piped to tank T-540. Liquids from tanks T-530 and T-540 are sent to the shipping tank. Three vertical pumps (P-550A, B, or C), located between the waste water tank and the slop oil tank, are used to pump the content of these tanks to the shipping tank. All liquids collected in the drain and sump system are pumped to the shipping tank, and through the oil line, to shore for treatment. A hydrocarbon dump station consisting of a 55 gallon drum that is equipped with an anti-syphon seal, receives all used oils and hydrocarbon liquids. A level controller operated pump discharges the liquids to the production drain receiver.

2.1.2 *Gas, Oil and Water Separation*: All separators are two phase (i.e., oil and gas). Oil leaving the well test header in the test oil lines is routed to a test separator. Block valves in the well test header allow the separator to handle all, two-thirds, one-half, or one-third of all wells in the well room. Test oil routed to a test separator will not necessarily enter that separator. If the vessel is full, test oil will be rerouted to an oil gathering line prior to entering that test separator.

Oil that actually flows through a test separator goes into a separator oil line, where it is eventually routed to the shipping tank (V-160). The pressure in each test separator is maintained at a pressure high enough to push the oil into the shipping tank. Each well room has an identical set of two test separators (V-100 and V-110, or V-120 and V-130) and one gross separator (V-140 or V-150). Each test separator has a capacity of 5,000 bpd. Each gross separator has a capacity of 25,000 bpd.

Oil that has entered the oil gathering line, either from the header or after bypassing a test separator, is sent to a gross separator. Each vessel normally services one well room. However, interconnecting piping permits one gross separator to handle both well rooms while the other vessel is out of service.

Oil that goes through the freewater knockout vessel and then through either the gross separator or test separators is routed to the shipping tank. The pressure in the freewater knockout vessel and separators is maintained at a sufficient level to push liquid into the shipping tank.

2.1.3 *Waste Water Treatment*: There are no waste water treatment facilities on this platform.

2.1.4 *Well Testing and Maintenance*: In order to measure individual well production rates, production is directed to one or more test separators. Fluid from the test separators is combined with fluid from the gross separators and sent to the shipping tank. Gas from the test separators is combined with gas from the gross separators and sent to the gas gathering system.

After a well workover is completed, the oil production from the well is started by producing the well to a test separator or well clean tank (V-180). This segregates the well from the rest of the producing wells. Producing the well into a test separator prevents upsetting the normal production on the platform should the new well have unanticipated flow surges. Producing the well into the well clean tank allows the lowering of the tubing pressure to a level which will facilitate flow. Additionally, it will prevent the separators from being contaminated with material left in the well from the workover.

2.1.5 *Emulsion Breaking and Crude Oil Storage*: The shipping tank (V-160) collects liquids from the freewater knockout vessel (V-220), four test separators (V-100, 110, 120, & 130), two gross separators (V-140 & 150), six gas scrubbers (V-310, 360, 390, 930, 970, & 990), the well clean tank (V-180), the flare scrubber (V-200), the two sub-deck wastewater tanks (T-530 & 540) and the production drain receiver (V-910). Liquid comes into the well clean tank from each well test header. As with the shipping tank, the well clean tank can service either well room. This tank has a cone bottom and water jetting connection to assist in solids removal. Following treatment in the well clean tank, liquids are sent through the well clean pump (P-190) to the shipping tank or to the production drains receiver (V-910).

2.1.6 *Emulsion Shipping*: Liquids are sent from the shipping tank to one of five multistage shipping pumps (P-170A, P-170 B, P 170 C, P1600, P1625) installed on the platform. One or more shipping pumps are operated simultaneously to provide the desired flow capacity. The shipping pumps send liquid through a 20-inch oil line to the LOGP. When an oil pig is being launched, the pumps direct oil through the oil pig launcher (L-220). Liquids that are sent through the shipping pumps to the oil pig launcher are then routed to the LOGP facility through a subsea oil pipeline.

2.1.7 *Gas Compression, Dehydration, and Disposition*: The produced gas system collects, transports, and distributes all gas produced on Platform Irene. The gas is shipped to shore after compression and dehydration. Produced gas is taken from the gathering lines at each wellhead and from other points in the crude handling system. Light liquid condensate is drawn off from the produced gas system and is returned to the shipping tank via P-320. Light liquids are also drawn from V-910 via P-920 A and B. There are six different pressure systems on the platform:

- Vapor Recovery System (VRS). The VRS collects miscellaneous vapors from the glycol regenerator, pressure relief valves, etc.
- Low Pressure System (20-50 psig). Collects gas from the test separators, gross separators, glycol flash separator, shipping tank, well clean tank, and all of the well casings.
- Intermediate Pressure System (175-225 psig). Collects gas from the discharge of the low stage compressor. A stream is taken off to provide make up gas for the well clean tank.
- High Pressure System (300-700 psig). Supplies make up gas to the shipping tank and the glycol flash separator as well as fuel to the flare pilot and purge. Its main purpose is to supply gas to the gas lift injection compressor (C-940). All excess is sent through the 8-inch line to shore.
- Gas Lift System (1,400 psig). Supplies gas to the gas lift system on the wells.
- Gas Injection System (2,200-2,600 psig). Supplies gas to an injection well.

The produced gas system is similar to the crude handling system in its passage from the wells to the sub-headers, test separators, and gross separators. Gas that becomes part of a gas gathering line is collected from six wells per sub-header of which there are in turn, six per well test header in each well room. Gas from the test gas line enters the gas gathering line if it does not enter the test separators, as with the crude oil system. However, if gas lines from the wells are capped off, gas enters the oil gathering line at the well test header. All low pressure gas that enters the oil gathering line is collected and cooled through the suction cooler (E-300) (also referred to as the fin fan section) after leaving the well test header and prior to entering the low pressure suction scrubber (V-310).

Other streams that enter the suction scrubber include recycle gas from the inter-stage scrubber (to maintain minimum pressure in the low pressure system) and condensate dumped from the inter-stage scrubber. Flash gas and condensate from the glycol flash separator are also sent to the suction scrubber. Liquids from the suction scrubber are pumped to the shipping tank.

Gas exiting the suction scrubber goes directly to the first stage compressors (C-330A or B). C-330A is a 1000 bhp unit and C-330B is a 1250 bhp unit. Both units are two-stage reciprocating compressors, with a typical individual maximum capacity of 7.5 MMscfd between low and intermediate pressure. Actual capacity is dependent upon suction and discharge pressures. If capacities higher than one machine can provide are required, both compressors can be operated simultaneously at partial or full capacity.

Following first-stage compression, intermediate pressure gas is sent to the inter-stage scrubber (E-360). If it becomes necessary at this point to maintain intermediate pressure, the gas is joined by recycled gas from the high pressure system (i.e., gas that has gone through the gas/glycol heat exchanger). Both the inter-stage cooler and scrubber have a nominal capacity of 15 MMscfd. Gas that exits the inter-stage scrubber is either recycled back to the low pressure system for pressure control, combined with low pressure gas to be used as make-up gas in the well clean tank, or sent to the second stage compressors (C-340A or B). Gas discharge from the high stage cylinders of the second stage compressor goes to the discharge from the high stage cylinders of the second stage compressor goes to the discharge or fin fan cooler section (E-370) for initial cooling. Final cooling occurs with seawater in the gas/seawater exchanger (E-380). This step maximizes cooling and liquid dropout prior to the gas being sent to the discharge scrubber (V-390). The gas/seawater exchanger is provided with a bypass for maintenance purposes. However, the additional cooling it provides reduces the water load on the glycol system by 50 percent. The discharge cooler, gas/seawater exchanger and the discharge scrubber have a nominal capacity of 15 MMscfd. Gas from the discharge scrubber is usually sent to the glycol contactor (V-400). This vessel is used to dehydrate the gas by glycol absorption prior to shipment to the HS&P facility on shore and the gas lift injection system. However, the glycol contactor and sales meter systems have a bypass so that they can be removed from service for maintenance while gas sales continue.

High pressure gas that enters the glycol system is dehydrated by contact with triethylene glycol in the glycol contactor. Gas flows up through the vessel while lean glycol enters the top and flows downward. Bubble trays provide the glycol-gas contact. The glycol with water, or rich glycol, collects in the bottom of the glycol contactor and is released. Rich glycol flows to the glycol reboiler where it is first heated by exchanger with hot lean glycol. This glycol then collects in the three phase flash separator. Any entrained gas or condensate from the glycol flash separator is then released to the low pressure gas system prior to entrance into the suction scrubber.

Compressor C-940 is operated for gas lift and/or gas injection depending on requirements. Gas enters the 3rd stage compressor from suction scrubber V-930. After 3rd stage compression is completed, gas flows to the inter-stage cooler E-970; however, if low pressure occurs in the 3rd stage suction, gas is recycled back to suction scrubber V-930. Gas enters compressor C-940 4th stage and is compressed to designed gas lift pressure, approximately 1,400 - 1,450 psig and proceeds to aftercooler E-980 and then to discharge scrubber V-99 for final liquid removal before use as gas lift. However, if low pressure occurs in the 4th stage suction, gas is recycled back to suction scrubber V-970. If a shutdown condition occurs during operation of the gas lift system, shut down valves (SDV-930, 93 1, 940, 970, 971, 950, and 955) will close and blow down valves (BDV-945 and 955) will open and vent pressure to flare.

The gas injection system is intended to operate when produced gas over and above gas lift requirements cannot be sent to shore or during maintenance and repair operations. In this condition, the excess gas will be injected into the Monterey formation through a designated well. The gas injection system consists of a 4-inch pipeline running from the fourth stage compressor discharge to a well head. Modifications to existing pressure controls are required to switch from normal compression system operation, in which excess gas is sent to shore, to the gas injection mode. Therefore, gas injection only occurs to preclude extended flare events.

2.1.8 *Gas Sweetening and Sulfur Recovery*: PXP has installed a skid-mounted gas sweetening system to scrub produced gas prior to any planned flaring event. The sulfa-check system also scrubs sulfur from all flare purge/pilot gas.

2.1.9 *Vapor Recovery Systems*: Platform Irene is equipped with a gas gathering system and a vapor recovery system. Low and high pressure gases are collected by the gas gathering system and is delivered by pipeline to the LOGP. The pressure relief valves for the compressor and other equipment handling hydrocarbon liquids or vapors discharge to the vapor recovery system. The pressure relief valves only open during emergency situations or mandatory testing. The gases flow to a flare scrubber (V-200). The scrubber retains any liquids which are then returned to the shipping tank.

2.1.10 *Heating and Refrigeration*: There are no fuel-fired process heaters or process refrigeration systems on Platform Irene.

2.1.11 *Flare Relief System*: Platform Irene is equipped with a flare system to minimize emissions of ROCs that would otherwise be emitted to the atmosphere.

2.1.11.1 *Flare System Design*: The flare system receives gas from relief valves, vents, and blowdown valves in gas service in the event that the platform vapor recovery system becomes inoperable. Light liquid condensate from the flare scrubber is released to the pressure drain system and returned to the shipping tank. All relief valves, vents, and blowdown valves in as service are connected to a flare header system. This includes relief mechanisms on the well test headers, test separators, gross separators, shipping tank, well clean tank, suction scrubbers, inter-stage scrubbers, discharge scrubber, gas/glycol heat exchanger, glycol flash separator, and the glycol reboiler/surge tanks, as well as from the inlet lines for the suction cooler, inter-stage cooler, gas/seawater exchanger, and the discharge scrubber. In the event that the vapor recovery system becomes inoperable, gases from these equipment items are collected in the flare line is sent to the flare scrubber (V-200). The gas then continues up the flare boom to the flare tip where it is burned. Vapors from the gas pig launcher are directed to V-910.

A mass flow meter is located in the flare line at the base of the flare stack (FL-205) to measure and record the gas that is flared. Its range of operation is 0.017 MMscfd minimum to 15.000 MMscfd maximum.

2.1.11.2 *Planned Flaring Events*: There are four common or routine planned flaring scenarios that occur on Platform Irene. All planned events are scrubbed to remove sulfur compounds. Planned flaring events are defined according to the provisions of Rule 359.

(1) During the start-up of each unit, an automatic cycle is initiated to sweep atmospheric air from the system. This minimizes the possibility of having combustible gas mixtures in the process.

(2) During the shutdown of equipment, shut down valves (SDV's) will close and blowdown valves (BDV's) will open automatically to release pressure from the system. This is a requirement of federal regulations.

(3) During maintenance of equipment, the systems are purged with nitrogen or fuel gas and blowdown to the flare system.

(4) During normal operations, low pressure flare gas may be released from the low pressure vents.

2.1.11.3 *Unplanned Flaring Events*: Unplanned flaring events are defined as all flaring that does not meet the definition of planned flaring under Rule 359. Unplanned flaring includes emergency and breakdown events.

2.2 Support Systems

2.2.1 *Pipelines*: The three pipelines associated with the platform include a 20-inch oil emulsion line, an 8-inch produced gas line and an 8-inch produced water line.

2.2.2 *Power Generation*: Electrical power is provided for all equipment, except the two pedestal cranes and emergency backup generators, by Pacific Gas & Electric (PG&E) through a submarine cable from shore. The platform has one 480 volt, 400 kw diesel powered emergency generator that is used in the event of interrupted power supply and two emergency drilling generators. The Motor Control Center (MCC) supplies power to critical equipment such as fire pumps and the control system if shore power should fail.

2.2.3 *Supply Boats*: When the platform is in production mode (i.e., no drilling or well repair) the supply boat activity is approximately 1-2 trips per month. While drilling or during well repair, the supply boat activity increases to about 1 trip every 3 days. The home port for PXP's supply boat is Port Hueneme.

2.2.4 *Crew Boats*: Crew boats are not used with Platform Irene.

2.2.5 *Helicopters*: Crew transfer is entirely via helicopter, which averages 3 round trips per day between Platform Irene and the Santa Maria Airport.

2.2.6 Man Overboard Boat: The Man overboard boat serves as an emergency rescue man overboard and platform emergency escape vessel.

2.2.7. *Escape Capsule*: The two escape capsules serve as platform emergency escape vessels.

2.3 Drilling Activities

2.3.1 *Drilling:* The drill rig on Platform Irene has been used intermittently since development drilling began in 1986. The rig has performed four drilling programs to date, including the well workover procedures. The rig and related equipment was specially designed for use on the platform. The major components on the drill rig, including the derrick and the superstructure, are maintained on the platform and are idle during non-drilling periods. Other rig equipment for drilling and workover operations are leased on an as-needed basis and provided by contractors. The drilling rig and associated equipment located on the platform are outfitted with electrical motors powered from the SCR house. The SCR house receives normal power from the PG&E cable from shore. Should there be a power interruption an emergency standby generator is activated to allow for securing the well operations.

2.3.2 *Well Workover*: Well workovers are accomplished by activating the resident electric-driven drilling rig on Platform Irene. Well workover activities occur on an as needed basis.

2.3.3 *Enhanced Recovery*: Enhanced oil recovery techniques are not employed on Platform Irene.

2.4 Maintenance/Degreasing Activities

2.4.1 *Paints and Coatings*: Maintenance painting on Platform Irene is conducted on a continuing basis. Normally only touch-up and equipment labeling/tagging is done with cans of spray paint.

2.4.2 *Solvent Usage*: Solvents not used for surface coating thinning may be used on the platform for daily operations such as well cuts. Usages include cold solvent degreasing and wipe cleaning with rags.

2.5 Planned Process Turnarounds

2.5.1 <u>Planned Process Turnarounds</u>: Process turnarounds on platform equipment are scheduled to occur when the onshore receiving facilities are required to shut down for maintenance. Major pieces of equipment such as gas compressors undergo maintenance as specified by the manufacturer. Maintenance of critical components is carried out according to the requirements of Rule 331 *{Fugitive Emissions Inspection and Maintenance}*. The emissions from planned process turnarounds are incorporated in the emissions category for planned flaring.

2.6 Other Processes

PXP asserts that no other processes exist that would be subject to permit.

2.7 Detailed Process Equipment Listing

Refer to the Tables in Attachment 10.3 for a complete listing of all permitted and exempt emission units.

3.0 Regulatory Review

This section identifies the federal, state and local rules and regulations applicable to Platform Irene.

3.1 Rule Exemptions Claimed

District Rule 202 (*Exemptions to Rule 201*): PXP requested a number of exemptions under this rule. An exemption from permit, however, does not necessarily grant relief from any applicable prohibitory rule. The following exemptions were approved by the District:

- Section 202.D.4 for helicopter trips required to transport platform personnel.
- Section 202.D.5 for temporary equipment where the projected emissions of all affected pollutants does not exceed one ton (except CO which shall not exceed 5 tons) and the use of each individual equipment does not exceed one 60 day period in any twelve month period.

- Section 202.D.6 (*De Minimis Exemption*). Based on PXP records, the current Platform Irene de minimis total is 10.40 lb/day of ROC emissions and 14.39b/day ROC for the Pt. Pedernales stationary source.
- Section D.8 for routine repair or maintenance of permitted equipment Section 202.D.14 for application of architectural coatings in the repair and maintenance of a stationary structure.
- Section D.14 for application of architectural coatings in the repair and maintenance of a stationary source.
- Section 202.F.1.c for a forklift rated at 45 bhp.

  - Temporary engines are used to support drilling and well workover activities. These engines are typically operated under the provisions of Rule 202.F.2 or 202.F.5. Applicability of permit requirements and associated controls for temporary engines are determined according to the rules in effect at the time of use.
- Section 202.H.1 for an abrasive blasting unit.
- Section 202.L.1 for ten heat exchangers.
- Section 202.U.2 for solvent application equipment and operations if the degreasing equipment contains unheated solvent and has a liquid surface area of less than 1 square foot and that the cumulative surface area of all the degreasers is less than 10 square feet.
- Section 202.U.3 for wipe cleaning using solvents as long as the solvents meet other applicable requirements and the use does not exceed 55 gallons per year.
- District Rule 321 (Control of Degreasing Operations): Per Section B.2, the four cold solvent degreasers are exempt from this rule.
- District Rule 331 (Fugitive Emissions Inspection and Maintenance): The following exemptions were applied for and approved by the District:
- Section B.2.b for components buried below the ground.
- Section B.2.c for one-half inch stainless steel tube fittings.
- There are four emergency-use internal combustion engines at this facility: two emergency electrical generators (drilling), one emergency electrical generator (production) and one emergency firewater pump. These ICES are exempt from Rule 333 per Rule 333 B.1.d.

3.2 Compliance with Applicable Federal Rules and Regulations

3.2.1 40 CFR Parts 51/52 {*New Source Review (Nonattainment Area Review and Prevention of Significant Deterioration*)}: As an existing OCS source permitted for the first time during original permitting of this facility, Platform Irene was not subject to New Source Review. However, all permit modifications as of September 4, 1992 are subject to District NSR requirements. Compliance with District Regulation VIII (*New Source Review*) ensures that future modifications to the facility will comply with these regulations.

3.2.2 40 CFR Part 55 *{OCS Air Regulation}:* Platform Irene is operating in compliance with the requirements of this regulation.

3.2.3 <u>40 CFR Part 60 *{New Source Performance Standards}*</u>*:* None of the equipment in this permit is subject NSPS requirements.

3.2.4 <u>40 CFR Part 61 *{NESHAP}*</u>*:* None of the equipment in this permit is subject NESHAP requirements.

3.2.5. *<u>40 CFR Part 63 {Maximum Achievable Control Technology}</u>:* On June 17, 1999, EPA promulgated Subpart HH, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage. PXP submitted information in October 2000 indicating this facility qualified for the "black oil" exemption per section 63.760(e)(1) of the subpart. The District approved this exemption request on June 5, 2002. Thus, only the recordkeeping requirements specified in condition 9.B.14 apply.

3.2.6 <u>*Subpart ZZZZ* {*NESHAP - Stationary Internal Combustion Engines*}</u>*:* The revised National Emission Standard for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE) was published in the Federal Register on January 18, 2008. An affected source under the NESHAP is any existing, new, or reconstructed stationary RICE located at a major source or area source.

Existing non-emergency non-black start compression ignition RICE rated less than 300 bhp must comply with the applicable emission and operating limits by no later than May 3, 2013. The following engines on the platform are subject to this requirement: North Crane (ID5082) and South Crane (ID5083). The following operating requirements apply:

(1) change the oil and filter every 1,000 hours of operation or annually, whichever comes first;

(2) inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first..

Notifications are not required for existing stationary emergency RICE.

Existing emergency standby compression ignition RICE must comply with the applicable operating limits by no later than May 3, 2013. The following engines on the platform are subject to this requirement: Emergency Drilling Generators (IDs 5460, 5461), Emergency Production Generator (ID 5084), and Emergency Firewater Pump (ID 5462). The following operating requirements apply:

(1) change the oil and filter every 500 hours of operation or annually, whichever comes first;

(2) inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

New stationary RICE that are subject to 40 CFR 60 Subpart IIII are not subject to any further requirements under 40 CFR 63 Subpart ZZZZ.

3.2.7 Subpart DDDDD *{Industrial/Commercial/Institutional Boilers and Process Heaters}*: Based on the MACT, there are no equipment items subject to this subpart.

3.2.8 Subpart EEEE *{Organic Liquid Distribution}:* Based on the MACT, there are no equipment items subject to this subpart.

3.2.9 40 CFR Part 64 {*Compliance Assurance Monitoring*}: This rule became effective on April 22, 1998 and affects emission units at the source subject to a federally enforceable emission limit or standard that use a control device to comply with the emission standard, and either pre-control or post-control emissions exceed the Part 70 source emission thresholds. Compliance with this rule was evaluated and it was determined that no emission units at this facility are currently subject to CAM. *Note: the emergency diesel engines and the flare do not use a control device to comply with a federally enforceable limit and the crane engines do not use "add-on" control devices for compliance with Rule 333.*

3.2.7 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to Platform Irene. Table 3.1 lists the federally-enforceable District promulgated rules that are "generic" and apply to Platform Irene. Table 3.2 lists the federally-enforceable District promulgated rules that are "unit-specific". These tables are based on data available from the District's administrative files and from PXP's Part 70 application for this permit. Table 3.4 includes the adoption dates of these rules.

In its Part 70 permit application (Form I), PXP certified compliance with all existing District rules and permit conditions. This certification is also required of PXP semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that PXP complies with the provisions of all applicable Subparts.

3.3 Compliance with Applicable State Rules and Regulations

3.3.1 Division 26. Air Resources {California Health & Safety Code}: The administrative provisions of the Health & Safety Code apply to this facility and will be enforced by the District. These provisions are District-enforceable only.

3.3.2 California Administrative Code Title 17: These sections specify the standards by which abrasive blasting activities are governed throughout the State. All abrasive blasting activities at Platform Irene are required to conform to these standards. Compliance will be assessed through onsite inspections. These standards are District-enforceable only. However, CAC Title 17 does not preempt enforcement of any SIP-approved rule that may be applicable to abrasive blasting activities.

3.3.3 Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines (CCR Section 93115, Title 17): This ATCM applies for all stationary diesel-fueled engines rated over 50 brake horsepower (bhp) at this facility. On March 17, 2005, District Rule 202 was revised to remove the compression-ignited engine (e.g. diesel) permit exemption for units rated over 50 bhp to allow the District to implement the State's ATCM for Stationary Compression Ignition Engines. Compliance shall be assessed through onsite inspections and reporting. The operating requirements and emission standards outlined in the ATCM do not apply to stationary diesel-fueled engines solely used on the OCS. However these OCS engines are required to meet fuel, recordkeeping, reporting, and monitoring requirements outlined in the ATCM. On January 30, 2006 the DICE ATCM was incorporated into 40 CFR Part 55, making the requirements of the DICE ATCM federally enforceable in the OCS.

3.3.4 California Administrative Code Title 17 {Sections 93118.5}: This section requires diesel-powered harborcraft to meet certain emission standards and operational requirements. New vessels brought into California must comply with this regulation immediately, while existing vessels must meet the compliance dates specified in the regulation.

3.4 Compliance with Applicable Local Rules and Regulations

3.4.1 Applicability Tables: In addition to Tables 3.1 and 3.2, Table 3.3 lists the non-federally enforceable District promulgated rules that apply to Platform Irene. Table 3.4 lists the adoption date of all rules applicable to this permit at the date of this permit's issuance.

3.4.2 Rules Requiring Further Discussion: This section provides a detailed discussion regarding the applicability and compliance of certain rules. The following is a rule-by-rule evaluation of compliance for this facility:

Rule 201 (Permits Required): This rule applies to any person who builds, erects, alters, replaces, operates or uses any article, machine, equipment, or other contrivance which may cause the issuance of air contaminants. The equipment included in this permit is listed in Attachment 10.6. An Authority to Construct is required to return any de-permitted equipment to service and may be subject to New Source Review.

Rule 301 - Circumvention: This rule prohibits the concealment of any activity that would otherwise constitute a violation of Division 26 (Air Resources) of the California H&SC and the District rules and regulations. To the best of the District's knowledge, the permittee is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for which a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringlemann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringlemann Chart. Sources subject to this rule include: the flare and all diesel-fired piston internal combustion engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules. Visible emissions monitoring is also required for the diesel engines and for planned flaring.

Rule 303 - Nuisance: This rule prohibits the OCS operator from causing a public nuisance due to the discharge of air contaminants. Based on the source's location on the OCS, the potential for public nuisance is small. This rule does not apply to the platform since it is not included in the OCS Air Regulation.

Rule 304 - Particulate Matter, Northern Zone: Platform Irene is a Northern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of 0.3 grain/scf. Sources subject to this rule include: the flare and all diesel-fired IC engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules. Rule 359 addresses the need for the flare to operate in a smokeless fashion.

Rule 309 - Specific Contaminants: Under Section "A", no source may discharge sulfur compounds and combustion contaminants in excess of 0.2 percent as SO_2 (by volume) and 0.3 gr/scf (at 12% CO_2) respectively. Sulfur emissions will comply with the SO_2 limit due to removal of sulfur prior to flaring. All diesel powered piston IC engines have the potential to exceed the combustion contaminant limit if not properly maintained (see discussion on Rule 304 above for compliance).

Rule 310 - Odorous Organic Compounds: This rule prohibits the discharge of H_2S and organic sulfides that result in a ground level impact beyond the property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. Platform Irene produces sour gas however, all planned flare gas is required to meet the Rule 359 limit of 796 ppm H_2S. This is achieved by the existing requirements to process all planned flare gas through an amine scrubber. An additional potential source of H_2S and organic sulfide emissions are from fugitive leaks from piping components handling sour gas. The implementation of a District-approved fugitive leak detection and repair inspection and maintenance program will minimize this potential. Implementation of these emission control requirements is expected to ensure compliance with this rule.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted to 0.5 percent (by weight) for liquids fuels and 50 gr/100 scf (calculated as H_2S) {or 796 ppmvd} for gaseous fuels. There is no natural gas fuel burning equipment on Platform. All piston IC engines on the Platform Irene and on the supply boat are expected to be in compliance with the liquid fuel limit since they are required to use CARB diesel fuel with 0.0015% sulfur content. The flare relief system is not subject to this rule (see discussion under Rule 359).

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the discharge of emissions of both photochemically and non-photochemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used on the platform during normal operations for degreasing by wipe cleaning and for use in paints and coatings in maintenance operations. There is the potential to exceed the limits under Section B.2 during significant surface coating activities. PXP will be required to maintain records to ensure compliance with this rule.

<u>*Rule 321 - Solvent Cleaning Operations*</u>: This rule was revised to fulfill the commitment in the Clean Air Plans to implement requirements for solvent cleaning machines and solvent cleaning. The revised rule contains solvent reactive organic compounds (ROCs) content limits, revised requirements for solvent cleaning machines, and sanctioned solvent cleaning devices and methods. These provisions apply to solvent cleaning machines and wipe cleaning.
PXP claimed an exemption per Section B.18 for two *Safety-Kleen* degreasers on the platform. This exemption covers single pieces of degreasing equipment, which use unheated solvent, and which have a liquid surface area of less than one square foot. The exemption was approved.

Rule 322 - Metal Surface Coating Thinner and Reducer: This rule prohibits the use of photochemically reactive solvents for use as thinners or reducers in metal surface coatings. PXP is required to maintain records during maintenance operations to ensure compliance with this rule.

Rule 323 - Architectural Coatings: This rule sets standards for the application of surface coatings. With certain exceptions, this rule limits the ROC content of architectural coatings to 250 grams/liter. The primary coatings utilized at this facility are Industrial Maintenance Coatings that have a limit of 250 gram ROC per liter of coating, as applied.

Rule 324 - Disposal and Evaporation of Solvents: This rule prohibits any source from disposing more than one and a half gallons of any photochemically reactive solvent per day by means that will allow the evaporation of the solvent into the atmosphere. PXP is required to maintain records to ensure compliance with this rule.

Rule 325 - Crude Oil Production and Separation: This rule, adopted January 25, 1994, applies to equipment used in the production, gathering, storage, processing and separation of crude oil and gas prior to custody transfer. The primary requirements of this rule are under Sections D and E. Section D requires the use of vapor recovery systems or solid roofs on all tanks and vessels, including waste water tanks, oil/water separators and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. Production and test separators are all connected to gas gathering systems and relief valves are connected to the vapor recovery system.

Five equipment items are subject to this rule: wastewater tanks 530 and 540 and sumps A, B and C. Tanks 530 and 540 are subject to section D.2 and are equipped with solid roof covers. The sumps are uncovered but are subject to rigorous monitoring requirements listed in permit condition 9.C.6. to ensure compliance with this rule.

Rule 326 - Storage of Reactive Organic Liquids: This rule applies to equipment used to store reactive organic compound liquids with a vapor pressure greater than 0.5 psia. The platform has a deck wash tank and slop oil tank with a capacity greater than 5,000 gallons. These tanks however, are subject to Rule 325 and therefore are not subject to this rule per Section B.1.c.

Rule 327 - Organic Liquid Cargo Tank Vessel Loading: There are no organic liquid cargo tank loading operations associated with Platform Irene.

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). There is one in-line hydrogen sulfide analyzer on the platform. This analyzer (Del Mar 4000) monitors the removal of sulfur from the planned flare gas to ensure compliance with the permitted planned flaring emission limits.

Rule 330 - Surface Coating of Metal Parts and Products: This rule sets standards for many types of coatings applied to metal parts and products. In addition to the ROC standards, this rule sets operating standards for application of the coatings, labeling and recordkeeping. It is not anticipated that PXP will trigger the requirements of this rule. Compliance shall be based on site inspections.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas production fields. PXP submitted an initial I&M Plan and received District approval of this Plan on April 18, 1994. Ongoing compliance with the provisions of this rule will be assessed via platform inspection by District personnel using an organic vapor analyzer and through analysis of operator records. Platform Irene does not perform any routine venting of hydrocarbons to the atmosphere. All gases routinely vented are directed to the flare relief system.

Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines: This rule applies to all engines with a rated brake horsepower of 50 or greater. The emergency standby IC engines at the facility include one firewater pump engines and three generators that are no longer exempt from permit. However, they are compression ignition emergency standby engines and are exempt from the provisions of the Rule per Section B.1.d. The two diesel-fired pedestal crane engines are subject to the NO_X, ROC, and CO standards under Section E.4. The revised Rule became effective on the OCS on November 21, 2008. Ongoing compliance will be achieved through implementation of the District-approved *Maintenance Plan* required under Section F and through source testing as applicable.

Rule 342 - Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters: This rule sets emission standards for external combustion units with a rated heat input greater than 5.0 MMBtu/hr. Platform Irene does not have any emission units subject to this rule.

Rule 343 - Petroleum Storage Tank Degassing: This rule applies to the degassing of any above-ground tank, reservoir or other container of more than 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 2.6 psia or between 20,000 gallons and 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 3.9 psia. Platform Irene is not subject to this rule because there are no emission units with a capacity in excess of 20,000 gallons.

Rule 346 - Loading of Organic Liquids: This rule applies to the transfer of organic liquids into an organic liquid cargo vessel. For this rule only, an organic liquid cargo vessel is defined as a truck, trailer or railroad car and, as such, this rule does not affect OCS sources.

Rule 353 – Adhesives and Sealants: This rule applies to the use of adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers. Compliance shall be based on site inspections.

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. Compliance with this rule has been documented. A detailed review of compliance issues is as follows:

§D.1 - Sulfur Content in Gaseous Fuels: Part (a) limits the total sulfur content of all planned flaring from North County flares to 50 gr/100 cubic feet (796 ppmv) calculated as H_2S at standard conditions. PXP installed a skid-mounted sulfa-check scrubber system to reduce the sulfur content from all planned flaring events (including purge and pilot gas) to below the rule limits.

During the permitting of Platform Irene, PXP requested that the District allow a daily monitoring program which confirms that "planned-continuous" flow rates and corresponding sulfur emissions are minimal and below the 796 ppmv H_2S limit. PXP established a program whereby daily monitoring of residual gases at the flare scrubber is conducted continuously by the Del Mar flare H_2S analyzer and has demonstrated that any "planned-continuous" flaring emissions are below Rule 359 limits. This program is fully described in the *Flare Minimization Plan for Platform Irene*.

§D.2 - Technology Based Standard: Requires all flares to be smokeless and sets pilot flame requirements. These requirements have been met. The flare on Platform Irene is in compliance with this section.

§D.3 - *Flare Minimization Plan*: This section requires sources to implement flare minimization procedures so as to reduce SO_x emissions. PXP has fully implemented their *Flare Minimization Plan* which was revised on July 14, 1997.

Rule 360 – Emissions of Nitrogen from Large Water Heaters and Small Boilers: The permittee shall comply with the requirements of this rule whenever a new boiler, process heater or other external combustion device is added or an existing unit is replaced. An ATC/PTO permit shall be obtained prior to installation of any grouping of Rule 360 applicable boilers or hot water heaters whose combined system design heat input rating exceeds 2.000 MMBtu/hr. An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane.

Rule 361 – Small Boilers, Steam Generators and Process Heaters: The permittee shall comply with the requirements of this rule whenever a new boiler, process heater or other external combustion device is added or an existing unit is replaced. An ATC permit shall be obtained prior to installation, replacement, or modification of any existing Rule 361 applicable boiler or water heater rated over 2.000 MMBtu/hr. An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane.

Rule 505 - Breakdown Conditions: This rule describes the procedures that PXP must follow when a breakdown condition occurs to any emissions unit associated with Platform Irene. A breakdown condition is defined as an unforeseeable failure or malfunction of (1) any air pollution control equipment or related operating equipment which causes a violation of an emission limitation or restriction prescribed in the District Rules and Regulations, or by State law, or (2) any in-stack continuous monitoring equipment, provided such failure or malfunction:

a. Is not the result of neglect or disregard of any air pollution control law or rule or regulation;

b. Is not the result of an intentional or negligent act or omission on the part of the owner or operator;

c. Is not the result of improper maintenance;

d. Does not constitute a nuisance as defined in Section 41700 of the Health and Safety Code;

e. Is not a recurrent breakdown of the same equipment.

Rule 603 - Emergency Episode Plans: Section "A" of this rule requires the submittal of *Stationary Source Curtailment Plan* for all stationary sources that can be expected to emit more than 100 tons per year of hydrocarbons, nitrogen oxides, carbon monoxide or particulate matter. PXP submitted such a plan on July 23, 1994. This Plan was updated on April 22, 1997 and December 12, 2000.

Rule 810 – Federal Prevention of Significant Deterioration: This rule was adopted January 20, 2011 to incorporate the federal Prevention of Significant Deterioration rule requirements into the District's rules and regulations. Future projects at the facility will be evaluated to determine whether they constitute a new major stationary source or a major modification.

3.5 Compliance History

This section contains a summary of the compliance history for this facility and was obtained from documentation contained in the District's Administrative file.

3.5.1 Variances: The following variance was granted to PXP for Platform Irene since the last permit renewal:

Emergency Variance Order (HB Case No. 11-03E) was granted 02/28/11 for the CARB PERP engines #126010 and #146727 - variance relief from 14-day notification requirement. All other PERP requirements remain in force.

3.5.2 Violations: The following Enforcement actions were taken since the last permit reevaluation:

VIOLATION TYPE	NUMBER	ISSUE DATE	DESCRIPTION OF VIOLATION
MIN	9461	04/19/2010	1) During a planned flaring event, burning produced gaseous fuel which contained sulfur compounds in excess of 50 grains per 100 cubic feet (796 ppmv) calculated as hydrogen sulfide at standard conditions (total event H2S = 4,000 ppmv) and 2) not operating the skid-mounted gas sweetening system during the above event.
NTC	9720	04/23/2012	Data was not properly recorded for the operation of the Delmar Flare Sulfur H2S analyzer during the end of the 1st quarter and beginning of the second quarter 2012 (through April 11, 2012) (after loss of 5% of quarterly data). The data capture requirements of 90 percent were not met (PTO 9106 Condition 9C.2(c)(iii) and the Flare Sulfur Monitoring Plan). No excess emissions occurred. Data during flaring events was manually recorded – no lost emission related data.

3.5.3 Hearing Board Actions: There have been no significant historical Hearing Board actions.

Table 3.1 - Generic Federally-Enforceable District Rules

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 101: Compliance by Existing Installations	All emission units	Emission of pollutants
RULE 102: Definitions	All emission units	Emission of pollutants
RULE 103: Severability	All emission units	Emission of pollutants
RULE 201: Permits Required	All emission units	Emission of pollutants
RULE 202: Exemptions to Rule 201	Applicable emission units, as listed in form 1302-H of the Part 70 application	Insignificant activities/emissions, per size/rating/function
RULE 203: Transfer	All emission units	Change of ownership
RULE 204: Applications	All emission units	Addition of new equipment or modification to existing equipment.
RULE 205: Standards for Granting Permits	All emission units	Emission of pollutants
RULE 206: Conditional Approval of ATC or PTO	All emission units	Applicability of relevant Rules
RULE 207: Denial of Applications	All emission units	Applicability of relevant Rules
RULE 208: Action on Applications - Time Limits	All emission units. Not applicable to Part 70 permit applications.	Addition of new equipment of modification to existing equipment.
RULE 212: Emission Statements	All emission units	Administrative
RULE 301: Circumvention	All emission units	Any pollutant emission
RULE 302 : Visible Emissions	All emission units	Particulate matter emissions
RULE 304: PM Concentration – North Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminants
RULE 311: Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur
RULE 310: Odorous Org. Sulfides	All emission units	Emission of organic sulfides
RULE 317: Organic Solvents	Emission units using solvents	Solvent used in process ops.
RULE 321: Solvent Cleaning Ops.	Emission units using solvents	Solvent used in process ops.

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 322: Metal Surface Coating Thinner and Reducer	Emission units using solvents	Solvent used in process operations.
RULE 323: Architectural Coatings	Paints used in maintenance and surface coating activities	Application of architectural coatings.
RULE 324: Disposal and Evaporation of Solvents	Emission units using solvents	Solvent used in process operations.
RULE 505.A, B1, D: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULE 603: Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	The Point Pedernales Stationary source is a major source.
REGULATION VIII: New Source Review	All emission units	Addition of new equip. or modification to existing equip. Applications to generate ERCs.
RULE 810: Federal Prevention of Significant Deterioration	New or modified emission units	Major modifications
RULE 901: New Source Performance Standards (NSPS)	All emission units	Applicability standards are specified in each NSPS.
RULE 1001: National Emission Standards for Hazardous Air Pollutants (NESHAPS)	All emission units	Applicability standards are specified in each NESHAP.
REGULATION XIII (RULES 1301-1305): Part 70 Operating Permits	All emission units	The Point Pedernales Stationary source is a major source.

Table 3.2 - Unit-Specific Federally-Enforceable District Rules

Unit-Specific Requirements	Affected Emission Units	Basis for Applicability
RULE 325: Crude Oil Production and Separation	Deck wash tank, T530, T540 and sumps A, B and C. (ID #'s 11-1, 11-2, 11-3, 11-4 and 11-5).	All pre-custody production and processing emission units
RULE 331: Fugitive Emissions Inspection & Maintenance	All components (valves, flanges, seals, compressors and pumps) used to handle oil and gas: ID #'s 4-1 thru 4-5 and 5-1 thru 5-5	Components emit fugitive ROCs.
RULE 333: Control of Emissions from Reciprocating IC Engines	Piston IC engines only. (No. and So. Pedestal Cranes) ID #s 1-1, 1-2	IC engines exceeding 100 bhp rating.
RULE 359: Flares and Thermal Oxidizers	Flare Relief System; ID # 3-1	Flaring.

Table 3.3 - Non-Federally-Enforceable District Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULE 310: Organic Sulfides	All emission units	Odorous sulfide emissions
RULE 352: Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters	New water heaters and furnaces	Upon installation
RULES 501-504: Variance Rules	All emission units	Administrative
RULE 505.B2, B3, C, E, F, G: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULES 506-519: Variance Rules	All emission units	Administrative

Table 3.4 - Adoption Dates of District Rules Applicable at Issuance of Permit

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 1981

Rule No.	**Rule Name**	**Adoption Date**
Rule 102	Definitions	March 17, 2011
Rule 103	Severability	October 23, 1978
Rule 106	Notice to Comply for Minor Violations	July 15, 1999
Rule 201	Permits Required	June 19, 2008
Rule 202	Exemptions to Rule 201	June 21, 2012
Rule 203	Transfer	April 17, 1997
Rule 204	Applications	April 17, 1997
Rule 205	Standards for Granting Permits	April 17, 1997
Rule 206	Conditional Approval of ATC or PTO	October 15, 1991
Rule 208	Action on Applications - Time Limits	April 17, 1997
Rule 212	Emission Statements	October 20, 1992
Rule 301	Circumvention	October 23, 1978
Rule 302	Visible Emissions	June 1981
Rule 303	Nuisance	October 23, 1978
Rule 304	Particulate Matter Concentration - Northern Zone	October 23, 1978
Rule 306	Dust and Fumes - Northern Zone	October 23, 1978
Rule 309	Specific Contaminants	October 23, 1978
Rule 310	Odorous Organic Sulfides	October 23, 1978
Rule 311	Sulfur Content of Fuels	October 23, 1978
Rule 317	Organic Solvents	October 23, 1978
Rule 321	Solvent Cleaning Operations	June 21, 2012
Rule 322	Metal Surface Coating Thinner and Reducer	October 23, 1978
Rule 323	Architectural Coatings	November 15, 2001
Rule 324	Disposal and Evaporation of Solvents	October 23, 1978
Rule 325	Crude Oil Production and Separation	July 19, 2001
Rule 326	Storage of Reactive Organic Compound Liquids	December 14, 1993
Rule 328	Continuous Emissions Monitoring	October 23, 1978

Rule No.	Rule Name	Adoption Date
Rule 331	Fugitive Emissions Inspection and Maintenance	December 10, 1991
Rule 333	Control of Emissions from Reciprocating ICEs	April 17, 1997
Rule 342	Control of Oxides of Nitrogen (NOx) from Boilers, Steam Generators and Process Heaters	April 17, 1997
Rule 343	Petroleum Storage Tank Degassing	December 14, 1993
Rule 344	Petroleum Sumps, Pits and Well Cellars	November 10, 1994
Rule 353	Adhesives and Sealants	June 21, 2012
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
Rule 360	Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers	October 17, 2002
Rule 361	Small Boilers, Steam Generators and Process Heaters	January 17, 2008
Rule 370	Potential to Emit – Limitations for Part 70 Sources	January 20, 2011
Rule 505	Breakdown Conditions (Section A, B1 and D)	October 23, 1978
Rule 603	Emergency Episode Plans	June 15, 1981
Rule 801	New Source Review	April 17, 1997
Rule 802	Nonattainment Review	April 17, 1997
Rule 803	Prevention of Significant Deterioration	April 17, 1997
Rule 804	Emission Offsets	April 17, 1997
Rule 805	Air Quality Impact and Modeling	April 17, 1997
Rule 806	Emission Reduction Credits	April 17, 1997
Rule 810	Federal Prevention of Significant Deterioration	January 20, 2011
Rule 901	New Source Performance Standards (NSPS)	September 20, 2010
Rule 903	Outer Continental Shelf (OCS) Regulations	November 10, 1992
Rule 1001	National Emission Standards for Hazardous Air Pollutants	October 23, 1993
Rule 1301	General Information	January 20, 2011
Rule 1302	Permit Application	November 9, 1993
Rule 1303	Permits	November 9, 1993
Rule 1304	Issuance, Renewal, Modification and Reopening	November 9, 1993

Rule No.	Rule Name	Adoption Date
Rule 1305	Enforcement	November 9, 1993

4.0 Engineering Analysis

4.1 General

The engineering analyses performed for this permit were limited to the review of:

- facility process flow diagrams
- emission factors and calculation methods for each emissions unit
- rule applicability for each emissions unit and process
- emission control equipment (including RACT, BACT, NSPS, NESHAP, MACT)
- emission source testing, sampling, CEMS, CAM
- process monitors needed to ensure compliance

Unless noted otherwise, default ROC/THC reactivity profiles from the District's document titled "*VOC/ROC Emission Factors and Reactivities for Common Source Types*" dated 7/13/98 (ver 1.1) was used to determine non-methane, non-ethane fraction of THC.

4.2 Stationary Combustion Sources

The stationary combustion sources associated with Platform Irene consist of diesel-fired piston internal combustion engines and the flare relief system. Primary power on the platform is supplied by a subsea electric cable connected to the Pacific Gas and Electric power grid.

4.2.1 *Piston Internal Combustion Engines*

4.2.1.1 *Crane Engines.* Both pedestal cranes are driven by Detroit Diesel Model 6-71N engines. The North crane engine is equipped with B-60 injectors and is rated at 210 bhp equipped while the South crane engine is equipped B-55 type injectors and is rated at 197 bhp. Use of B-type injectors will reduce NO_x emissions. The emission factors for PM, CO and ROC are from USEPA AP-42, Table 3.3-1 and the SO_x emission factor is based on mass balance calculation. The NO_x emission factors are based on District Rule 333 limit of 8.4 g/bhp-hr. Attachment 10.1 shows how the emission factor is derived. Rule 333 requires compliance with either a standard of 8.4 g/bhp-hr or 797 ppmv NO_x at 15 percent O_2. Source test results over the past five years have demonstrated compliance with the 797 ppmv emission limit.

Diesel fuel flow metering is accomplished by use of positive displacement meters on both crane engines, fire water pump, production generator and drilling generators. On a weekly basis, the day tanks for each engine are filled and that amount is logged for reporting purposes. The emergency electrical generator engines (production and drilling) and the fire water pump engine are equipped with non-resettable hour meters and the actual engine usage is logged during each time the engine is fired. Ongoing compliance with Rule 333 is accomplished by instituting quarterly inspections per Section E and biennial source testing.

The two crane engines are subject to permit and Rule 333 requirements. The calculation methodology for the crane engines is similar for all stationary IC engines:

$$ER = [(EF \times BHP \times BSCF \times LCF \times HPP) \div 10^6]$$

where:	ER	= emission rate (lb/period)
	EF	= pollutant specific emission factor (lb/MMBtu)
	BHP	= engine rated max brake-horsepower (bhp)
	BSFC	= engine brake specific fuel consumption (Btu/bhp-hr)
	LCF	= liquid fuel correction factor, LHV to HHV
	HPP	= operating hours per time period (hrs/period)

The emission factor is an energy based value using the higher heating value (HHV) of the fuel. As such, an energy based BSFC value must also be based on the HHV. Manufacturer BSFC data are typically based on lower heating value (LHV) data and thus require a conversion (LCF) to the HHV basis. For diesel fuel oil, the HHV values are typically 6 percent greater than the corresponding LHV data. Volume or mass based BSFC data do not need any conversions.

4.2.1.2 *Emergency Use Internal Combustion Engines*

Internal Combustion Engines. There are four emergency use internal combustion engines at this facility; one emergency firewater pump, one emergency electrical generator (production) and two emergency electrical generators (drilling). These units, previously exempt, were permitted under PTO 11922 on June 22, 2006. This permit was issued due to the March 17, 2005 revision to District Rule 202 *{Exemptions to Rule 201}* that resulted in the removal of the compression-ignited engine (e.g., diesel) permit exemption for units rated over 50 brake horsepower (bhp). That exemption was removed to facilitate implementation of the State's Airborne Toxic Control Measure for Stationary Compression Ignition Engines (DICE ATCM). The requirements of PTO 11922 are incorporated into this permit.

Mass emission estimates for the electrical generator engine are based on the maximum allowed hours for maintenance and testing. Emissions are determined by the following equations:

E1, lb/day = Engine bhp * EF (g/bhp-hr) * Daily Hours (hr/day) * (lb/453.6 g)
E2, tpy = Engine bhp * EF (g/bhp-hr) * Annual Hours (hr/yr) * (lb/453.6g) *(ton/2000 lb)

The emission factors (EF) were chosen based on each engine's rating and age. Default emission factors are used as documented on the District's webpage at http://www.sbcapcd.org/eng/atcm/dice/dice_efs.htm. Daily emissions are based on 2 hrs/day and annual emissions on 200 hours/yr.

4.1.2.3 *Miscellaneous Internal Combustion Engines*

The other stationary IC engines on the platform rated include a fork lift, two escape capsules and a MOB boat. (See section 4.4 for additional discussion on the escape capsules and the MOB). The calculation methodology for these engines is the same as the crane engines listed above in section 4.2.1.1.

4.2.2 *Flare Relief System*: The flare relief system consists of both a high and low pressure header that connects to various PSVs on production and test vessels, compressors, glycol system and pigging vessels. Further, both planned and unplanned flaring events occur. The flare itself is a National Airoil model 8MNJM utilizing air assist. The emission factors are based on the most current update (Supplement D - March 1998) of AP-42, Chapter 3, Section 4. These factors are consistent with the Table 3.1.1 of the District's Flare Study Phase I Report (July 1991). The more conservative emission factor is used regardless of the most recent update.

The design heat release is 625 MMBtu/hr. Sulfur oxide emissions are based on mass balance calculations assuming both planned and pilot/purge sulfur levels at 796 ppmv and unplanned flaring sulfur levels at 3,000 ppmv. All flaring scenarios utilize the same emission factors. The emissions for both planned and unplanned flaring events are calculated. The primary difference, besides, the volume of gas, is the sulfur content. Planned flaring must meet the Rule 359 emission standard of 50 gr/100 scf (796 ppmv), while the unplanned flaring depends on the sulfur content of the produced gas. The SO_x emission factor is determined using the equation: (0.169)(ppmv S)/(HHV). The calculation methodology for the flare is:

$$ER = [(EF \times SCFPP \times HHV) \div 10^6]$$

<u>where</u>:	ER	= emission rate (lb/period)
	EF	= pollutant specific emission factor (lb/MMBtu)
	SCFPP	= gas flow rate per operating period (scf/period)
	HHV	= gas higher heating value (Btu/scf)

The flare header is equipped with a Fluid Components LT81 Gas Flow Transmitter that is capable of detecting flow rates between 0.017 - 15.000 MMSCFD. The low flow, or minimum, detection limit is equivalent to 707 scfh which is much greater that the purge/pilot flow rate of 45 scfh. As such, there is no practical method for assessing flow rates between 45 and 707 scfh. Therefore, based on EPA and CARB's data reporting guidelines, a value of half the minimum detection limit is being assumed as "continuous" planned flaring. The sulfur content of the unplanned flaring event gases is determined by the daily measuring the sulfur content of the produced gas by Draeger tube (or equivalent District-approved device). The planned flaring gas sulfur content is measured using the Del Mar 4000 hydrogen sulfide monitoring device incorporated in the gas sweetening skid unit. The pilot/purge gas sulfur content is measured with a Draeger tube (or equivalent District-approved device).

To meet the requirements of District Rule 359, PXP has installed a produced gas sweetening system to scrub hydrogen sulfide from the pilot/purge and planned flaring events. The system design, installed as a skid-mounted package unit, was reviewed and approved by the District. Compliance is assessed by H_2S analysis using the Del Mar H_2S analyzer.

4.3 Fugitive Hydrocarbon Sources

Emissions of reactive organic compounds from piping components such as valves, flanges and connections are based on emission factors pursuant to District P&P 6100.061 (*Determination of Fugitive Hydrocarbon Emissions at Oil and Gas Facilities Through the Use of Facility*

Component Counts - Modified for Revised ROC Definition). The component leak-path was counted consisted with P&P 6100.061. This leak-path count is not the same as the "component" count required by District Rule 331. Both gas/light liquid and oil side components are in service at this facility.

The number of emission leak-paths were determined by the operator and these data were verified by District staff by checking a representative number of P&IDs and by site checks. The total number of component leak-paths subject to permit are listed in Table 5.1-1. These totals do not include component leak-paths which have been added to platform Irene but qualified for the Rule 202 de minimis exemption, thereby, exempting them from permit. The calculation methodology for fugitive emissions is:

$$ER = [(EF \times CLP \div 24) \times (1 - CE) \times (HPP)]$$

<u>where</u>:	E	= emission rate (lb/period)
	EF	= ROC emission factor (lb/clp-day)
	CLP	= component leak-path (clp)
	CE	= control efficiency
	HPP	= operating hours per time period (hrs/period)

An emission control efficiency of 80 percent is credited to all components that are safe to monitor (as defined per Rule 331) due to the implementation of a District-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements. Unsafe to monitor components are not eligible for I&M control credit. Ongoing compliance is determined by inspection with an organic vapor analyzer and verification of operator records.

4.4 Supply Boats

PXP uses the Santa Cruz as a supply boat in support of Platform Irene. Platform personnel are transported by helicopter. For supply boats, PXP has identified two types of boats. One type is for primary usage that is controlled for NO_x and the other is used as a spot-charter (identified as "uncon" in Table 5.5-1) and is normally uncontrolled for NO_x. The spot-charter usage is limited to 10 percent of actual boat usage based on the number of round trips made.

PRIMARY SUPPLY BOAT - The primary supply boat now assigned to service Platform Irene is the Santa Cruz. Supply boat emissions are based on the Santa Cruz engines. PXP informed the District in September 2009 that the Victory Seahorse no longer operates in Santa Barbara County waters, therefore all permit conditions and references to this vessel have been removed from the permit.

Main Engines - The Santa Cruz is equipped with two main propulsion diesel-fired IC engines (CAT 3516B). These engines are rated at 2,000 bhp at 1,600 rpm for continuous duty. These engines are optimized for low emissions (NO_x) through use of Dual Advanced Diesel Engine Management (ADEMII) modules with electronically controlled unit injectors, as well as dual turbochargers and a separate circuit aftercooler core. The NO_x emission factor, initially on the manufacturer February 24, 1999 letter guaranteeing 5.48 g/bhp-hr, was subsequently increased to 5.99 g/bhp-hr under ATC/PTO 11435. The conversion of this value into an enforceable emission factor in units of 270 lb/1000 gallons is documented in Section 10.1 of this permit. The BSFC (engine efficiency) value of 0.345 lb/bhp-hr was selected to reflect the approximate engine cruise mode load rating of 65 percent and was obtained from the manufacturer data sheets. ROC and CO emission factors taken from USEPA, AP-42 (Volume II) have been updated to reflect the larger size of these engines. The SO_x emission factor reflects a fuel sulfur content of 0.0015 weight percent.

Auxiliary Engines - Auxiliary diesel-fired engines on this vessel include two-170 kW CAT 3306B DIT generator sets each powered by identical 245 bhp engines and one bow thruster powered by a CAT 3408C DITA 510 bhp engine. These auxiliary engines are not controlled. The emission factors for these and the bow thruster engines are taken from USEPA AP-42. The SOx emission factor is based on mass balance and reflects a fuel sulfur content of 0.2 weight percent.

CALCULATION METHODS: The permit assesses emission liability based solely on a single emission factor (the cruise mode). The calculation methodology for the supply boat main engine emissions is:

$$ER = [(EF \times EHP \times BSFC \times EL \times TM) \div (10^3)]$$

<u>where</u>: ER = emission rate (lbs per period)
EF = full load pollutant specific emission factor (lb/1000 gallons)
EHP = engine max rated horsepower (bhp)
BSFC = engine brake specific fuel consumption (gal/bhp-hr)
EL = engine load factors (percent of max fuel consumption)
TM = time in mode (hours/period)

The calculations for the auxiliary engines are similar, except that a 50 percent engine load factor for the generators is utilized. Compliance with the main engine controlled emission rates shall be assessed through emission source testing. Ongoing compliance with quarterly and annual supply boat emission limits is assessed through implementation of the District-approved *Boat Monitoring and Reporting Plan* (July 2006) that requires "per-trip" fuel monitoring data.

Emergency response boat emissions are based on the *Clean Seas III*. The engines on this boat are uncontrolled. The approximate total engine horsepower, including auxiliary engines, is 4,400 bhp (two-1,500 bhp main engines, one-500 bhp bow thruster, two-300 bhp generators and one-600 bhp firewater pump). Emissions liability is assigned in a prorated fashion among the four OCS platforms who utilize the boat. Emission factors, calculations and compliance procedures are the same as for the spot-charter supply boats discussed above. The *Clean Seas III* has been replaced with two new vessels: the *Ocean Scout* and the *Ocean Guardian*. Only one of these vessels is in service at a time. The new vessels are equipped with Tier II main engines and Tier IV auxiliary generators. The total rated bhp and the PTE of each new vessel is less than the *Clean Seas III*'s.

MOB - (Man Overboard) vessel is a 17' Boston Whaler equipped with two 40 Bhp 2-cycle, gasoline-fired, spark ignited engines. Emissions are based on g/Bhp emission factors and a 200-hour per year operating limit.

Escape Capsules - Two (2), each equipped with a gasoline-fired, spark ignited engine rated at 58 bhp. Emissions are based on g/Bhp emission factors and a 200-hour per year operating limit.

The MOB and escape capsules are subject to permit since they are marine vessels associated with the stationary source.

4.5 Sulfur Recovery Units/Gas Sweetening Units

As part of the OCS Air Regulation Compliance Plan process, PXP has installed a sulfa-check based gas sweetening unit. The purpose of the control device is to remove hydrogen sulfide from produced gas sent to the flare relief system during planned flaring events and to treat all flare purge/pilot gas. The control device is a skid-mounted design and is equipped with a hydrogen sulfide analyzer and process controls to ensure that the sulfur limits of Rule 359 are achieved. Spent solution is transferred to the shipping tank (V-160) and subsequently injected into the emulsion pipeline via the shipping pumps for processing at the onshore treatment facility. The design parameters and drawings were reviewed by the District to ensure that the system would meet Rule 359 requirements. Of concern to the District in the revised design was the ability to knock-out entrained amine injected at the purge/pilot gas ejector (EJ-100). To alleviate these concerns, the design was modified to include a high efficiency mist eliminator downstream of this ejector. This, coupled with the existing flare scrubber (V-200), should ensure that the reacted amine is removed from the gas stream prior to being flared.

4.6 Tanks/Vessels/Sumps/Separators

Tanks: Platform Irene has two diesel fuel storage tanks and tanks T-530 and T-540. The diesel storage tanks service the various IC engines on the platform and are not controlled. Liquids from the sub-deck sumps are sent to tank T-530. T-530 flows to T-540. Liquids from the deck drains are sent to tank T-540 and then onto to the shipping tank. Both tanks (T-530, T-540) are covered. These tank emissions are small and are assumed to be less than 0.10 tpy (200 lb/yr). The detailed tank calculations for compliance will be performed using the methods presented in USEPA AP-42, Chapter 12. Tanks T-530 and T-540 emissions are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California*, January 1983). These tanks are classified as being in secondary production and heavy oil service. The calculation is:

$$ER = [(EF \times SAREA /24 \times (1-CE) \times (HPP)]$$

where:	ER	=	emission rate (lb/period)
	EF	=	ROC emission factor (lb/ft^2-day)
	SAREA	=	unit surface area (ft^2)
	CE	=	control efficiency
	HPP	=	operating hours per time period (hrs/period)

For open top tanks, no control efficiency is assigned. A leak free cover with properly operated PVRVs is approximately 85 percent efficient and hookup to vapor recovery is assigned a 95 percent control efficiency.

Vessels: Platform Irene has many pressure vessels (e.g., gross separators, test separators, shipping tank, compressor scrubbers, flare scrubber, glycol flash tank). All pressure vessels, except for the freewater knockout vessel (V-220) & Production drain receiver (V-910), are connected to the platform's gas gathering system. All PSVs are connected to the vapor recovery system (VRS). The production drain receiver is connected to the pressure drain system, taking fluids from the oil relief line and relieves any excess gases directly to the VRS. Emissions from pressure vessels are due to fugitive hydrocarbon leaks from valves and connections.

Sumps: There are three sub-deck sumps that recover any liquids that spill onto the sub-deck. Liquids from these sumps are sent to the slop oil tank and then onto to the shipping tank. All three sumps (S-500A, S-500B, S-500C) are uncovered and are subject to specific monitoring procedures detailed in permit condition 9.C.6. The calculations for the sumps are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California*, January 1983). The sumps are classified as secondary production and heavy oil service. The calculation is the same as for waste water tanks.

4.7 Vapor Recovery Systems

All produced gas from the production separators and pressure vessels, except for the production drains receiver and the glycol reboiler vent, are connected to the gas gathering system for dehydration, compression and shipment to onshore facilities. The glycol reboiler vent & Production drains receiver are connected to the vapor recovery system.

4.8 Helicopters

Helicopters are used on Platform Irene to transport crew from the Santa Maria airport. Both Sikorsky S-76 and Bell 212 helicopters are used with typical round-trip times of 50 minutes in duration. Emission factors, in units of "lb/hr", for different type of helicopters have been established for each operating mode based on the turbine engine used. These modes (idle, climb, cruise and decent) make up the total cycle time for each trip segment. For Platform Irene, there are two identical trip segments (Santa Maria Airport to Platform Irene and Platform Irene to the Santa Maria Airport). The emission rate per trip segment is calculated as:

$$ER = \sum_{mode} [EF_{mode} \text{ x } TIM]$$

where:
- ER = emission rate per trip segment (lb/segment)
- EF = pollutant specific emission factor per mode (lb/engine-hr)
- TIM = time in mode (hr)

With this data, a platform specific emission rate per trip segment is calculated. For Platform Irene, the one trip segment is simply doubled to obtain an emission rate per trip. Emissions tracking will be accomplished by reporting the number of trips by helicopter type.

4.9 Other Emission Sources

The following is a brief discussion of other emission sources on Platform Irene:

Pigging: Pipeline pigging operations occur on the platform. These consist of oil and gas pig launchers to onshore facilities. After all pig launches, the launcher is depressurized to the flare relief system via the production drains vessel (V-910). There are a remaining few pounds of back pressure on the launcher that are emitted when opened to the atmosphere. Emissions occur during the depressurization of the launcher units. The District has assumed that this remaining pressure cannot exceed 5 psig. The calculation per period is:

$$ER = [V_1 \text{ x } \rho \text{ x } wt\ \% \text{ x } EPP]$$

<u>where</u>:
- ER = emission rate (lb/period)
- V_1 = volume of vessel (ft^3)
- P = density of vapor at actual conditions (lb/ft^3)
- wt % = weight percent ROC-TOC
- EPP = pigging events per time period (events/period)

General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurring on Platform Irene as part of normal daily operations includes small cold solvent degreasing and wipe cleaning. Mass balance emission calculations are used assuming all the solvent used evaporates to the atmosphere.

Surface Coating: Surface coating operations typically include normal touch up activities. Entire platform painting programs are performed once every few years. Emissions are determined based on mass balance calculations assuming all solvents evaporate into the atmosphere. Emissions of PM/PM_{10} from paint overspray are not calculated due to the lack of established calculation techniques.

Abrasive Blasting: Abrasive blasting with CARB certified sands may be performed as a preparation step prior to surface coating. Particulate matter is emitted during this process. A general emission factor of 0.01 pound PM per pound of abrasive is used (SCAQMD - Permit Processing Manual, 1989) to estimate emissions of PM and PM_{10} when needed for compliance evaluations. A PM/PM_{10} ratio of 1.0 is assumed.

Mud Cuttings Roll Off Bins: This tank is used during drilling or work over operations to store cuttings from the drilling mud and for maintenance and tank cleaning operations. The emissions from this bin are estimated by using the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California,* January 1983). The mud cuttings bin is best classified as being similar to a well cellar in its emissions profile (heavy crude service). The equation used is similar to the sump/waste tanks discussed above.

4.10 BACT/NSPS/NESHAP/MACT

Except as described below in Table 4.2, there are no emission units at Platform Irene subject to best available control technology (BACT). Additionally, pursuant to Rule 331.E.1.b, all leaks from critical components are required to be replaced with BACT in accordance with the District's NSR rule.

NESHAPS/MACT: A National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage was promulgated on June 17, 1999. As described in section 3.2.5, this facility qualified for the black oil exemption and is required only to maintain the records specified in permit condition 9.B.14.

Existing engines on the platform are subject to NESHAP ZZZZ. New engines on Platform Irene are subject to NSPS IIII.

4.11 CEMS/Process Monitoring/CAM

4.11.1 CEMs: There are no in-stack continuous emission monitoring systems used on Platform Irene to measure criteria pollutant emissions. However, one hydrogen sulfide analyzer is installed on platform Irene that has been classified as a CEMs. This is the flare gas H_2S analyzer (Del Mar 4000) which monitors the H_2S concentration of the planned flare gas. This analyzer is subject to the *Platform Irene Process Monitor Calibration and Maintenance Plan* (revised May 11, 2009) and to the District's CEM Protocol document (dated October 22, 1992) and any subsequent revisions.

4.11.2 Process Monitoring: In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by the use of process monitoring systems. Examples of these monitors include: engine hour meters, fuel usage meters, water injection mass flow meters and flare gas flow meters. Once these process monitors are in place, it is important that they be well maintained and calibrated to ensure that the required accuracy and precision of the devices are within specifications. At a minimum, the following process monitors are required to be calibrated and maintained in good working order:

- Supply Boat Diesel Fuel Meters (main engines only)
- Hour Meters (cranes, emergency generator)
- Flare Header Flow Meter

To implement the above calibration and maintenance requirements, a *Process Monitor Calibration and Maintenance Plan* was submitted by PXP and approved by the District on January 4, 1995. This plan was most recently revised on May 11, 2009 and takes into consideration manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment is be utilized.

4.11.3 There are no emission units at this facility subject to the USEPA's Compliance Assurance Monitoring Assurance (CAM) rule.

4.12 Source Testing/Sampling

Source testing and sampling are required in order to ensure compliance with permitted emission limits, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. Table 4.1 details the pollutants, test methods and frequency of required testing. PXP will be required to follow the District *Source Test Procedures Manual* (May 24, 1990 and all updates). The following emission units are required to be source tested.

- North Crane Engine
- South Crane Engine
- Supply Boat Main Engines

At a minimum, the process streams below are required to be sampled and analyzed:

- Produced Gas: Sample taken at production separator outlet. Analysis for: HHV, total sulfur, hydrogen sulfide, composition. Samples to be taken on an annual basis.
- Produced Oil: Sample taken at outlet from production separator. Analysis for: API gravity; true vapor pressure (per Rule 325 methods). Samples to be taken on a biennial basis.
- Purge and Pilot: Sample taken at flare header. Analysis for: HHV, total sulfur, hydrogen sulfide, composition.

TABLE 4.1 - SOURCE TEST REQUIREMENTS

Emission Points	Pollutants/ Parameters	Test Methods
- Crane Engines	NO_x (ppmv, lb/hr)	CARB 1-100 or USEPA 7E
- Supply Boat Main Engines		

CO (ppmv, lb/hr)	CARB 1-100 or USEPA 10
ROC (ppmv, lb/hr)	USEPA 18
Fuel Flow Rate	meter
Fuel High Heating Value	ASTM
Total Sulfur Content	ASTM

Site Specific Requirements

a. All emissions tests to consist of three 40-minute runs. Crane engine tests to consist of three 20-minute runs. Crane engine to be tested at safe maximum load. Supply boat main engines to be tested at cruise load. Additional testing may be required if loads are not achieved.

b. The specific project crew and supply boat to be tested shall be determined by the District.

c. USEPA methods 1-4 to be used to determine O_2, dry MW, moisture content, CO_2, and stack flow rate. Alternatively, USEPA 19 may be used to determine stack flow rate.

d. SO_x emissions to be determined by mass balance calculation.

e. The main engines from the supply boat shall be tested annually. The crane engine shall be tested biennially.

f. Procedures to obtain the required operating loads shall be clearly defined in the source test plan.

TABLE 4.2 – RULE 331 BACT REQUIREMENTS

Component	Technology	Performance Standard
Well head Clamp ID No. 152608.001	API ring rated at 150% of process pressure	100 ppm as methane above ambient, monitored per EPA Reference Method 21
Valve Stem ID No. A121103.000	Penberthy Gage Valve - Low Emission Design Valve (e.g., graphite packing)	100 ppm as methane above ambient, monitored per EPA Reference Method 21.

5.0 Emissions

5.1 General

Emissions calculations are divided into "permitted" and "exempt" categories. Permit exempt equipment is determined by District Rule 202. The permitted emissions for each emissions unit is based on the equipment's potential-to-emit (as defined by Rule 102). Section 5.2 details the permitted emissions for each emissions unit. Section 5.3 details the overall permitted emissions for the facility based on reasonable worst-case scenarios using the potential-to-emit for each emissions unit. Section 5.4 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301. Section 5.5 provides the estimated emissions from permit exempt equipment and also serves as the Part 70 list of insignificant emission. Section 5.6 provides the net emissions increase calculation for the facility and the stationary source. For purposes of tracking facility emissions facility the District uses a computer database. Attachment 10.4 contains the District's documentation for the information entered into that database.

5.2 Permitted Emission Limits - Emission Units

Each emissions unit associated with the facility was analyzed to determine the potential-to-emit for the following pollutants:

- Nitrogen Oxides (NO_x) [3]
- Reactive Organic Compounds (ROC)
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x) [4]
- Particulate Matter (PM) [5]
- Particulate Matter smaller than 10 microns (PM_{10})
- Greenhouse Gases (GHG)

Permitted emissions are calculated for both short term (hourly and daily) and long term (quarterly and annual) time periods. Section 4.0 (Engineering Analysis) provides a general discussion of the basic calculation methodologies and emission factors used. The reference documentation for the specific emission calculations, as well as detailed calculation spreadsheets, may be found in Section 4 and Attachments 10.1 and 10.2 respectively. Table 5.1-1 provides the basic operating characteristics. Table 5.1-2 provides the specific emission factors. Tables 5.1-3 and 5.1-4 shows the permitted short-term and permitted long-term emissions for each unit or operation. In the table, the last column indicates whether the emission limits are federally enforceable. Those emissions limits that are federally enforceable are indicated by the symbol "FE".

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[3] Calculated and reported as nitrogen dioxide (NO_2)

[4] Calculated and reported as sulfur dioxide (SO_2)

[5] Calculated and reported as all particulate matter smaller than 100 μm

5.3 Permitted Emission Limits - Facility Totals

The total potential-to-emit for all emission units associated with the facility was analyzed. This analysis looked at the reasonable worst-case operating scenarios for each operating period. The equipment operating in each of the scenarios are presented below. Unless otherwise specified, the operating characteristics defined in Table 5.1-1 for each emission unit are assumed. Table 5.2 shows the total permitted emissions for the facility.

Supply boat emissions associated with platform Irene are those within a 25-mile radius of Platform Irene. Total supply boat emissions (ESE) for the Point Pedernales Project are the emissions within the 25-mile platform radius and the emissions from the 25-mile radius to the county line. See Table 5.2 of this permit for the 25-mile emissions and Table 5.4 of PTO 6708 for total ESE.

Hourly and Daily Scenario:

- Emergency internal combustion engines (generators and firewater pump)
- North and South pedestal crane engines
- Flare purge and pilot
- Planned continuous flaring
- Spot charter supply boat
  Main engines operating at cruise mode
  Generator engines on supply boat provide half of maximum engine rating*
  Bow thruster on supply boat does not operate during peak hour*
- Fugitive components
- Oil pig launcher
- Gas pig launcher
- Sub-deck sumps A, B, C
- Waste water tanks (530, 540)
- Solvent usage
- Roll-off bins (4x)
- MOB and Escape Capsule vessels

Quarterly and Annual Scenario:

- Emergency internal combustion engines (generators and firewater pump)
- North and South pedestal crane engines
- Flare purge and pilot
- Planned continuous flaring
- Planned intermittent (other) flaring
- Unplanned flaring
- Controlled and Uncontrolled supply boat
  Main engines operating at cruise mode
  Generator engines on supply boat provide half of maximum engine rating*
  Bow thruster*
- Emergency response boat
- Fugitive components
- Oil and Gas pig launchers and receivers

- Sub-deck sumps A, B, C
- Waste water tanks (530, 540)
- Solvent usage
- Roll-off bins (4x)
- MOB and Escape Capsule vessels

* Compliance basis for auxiliary engine emission limits (generators and bow thruster) is the combined total emission limits for all auxiliary engines.

5.4 Part 70: Federal Potential to Emit for the Facility

Table 5.3 lists the federal Part 70 potential to emit. Being subject to the OCS Air Regulation, all project emissions, except fugitive emissions, are counted in the federal definition of potential to emit. However, fugitives are counted in the Federal PTE if the facility is subject to any applicable NSPS or NESHAP requirement.

5.5 District Exempt Emission Sources/Part 70 Insignificant Emissions

Per Rule 202, maintenance activities such as painting and surface coating qualify for a permit exemption, but may contribute to facility emissions.

Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. The following emission units are exempt from permit per Rule 202, but are not considered insignificant emission units, since these exceed the insignificant emissions threshold:

- Solvents/Surface coating operations used during maintenance operations.

Table 5.4 presents the estimated annual emissions from these exempt equipment items, including those exempt items not considered insignificant.

5.6 Net Emissions Increase (NEI) Calculation

The net emissions increase for this facility and the entire stationary source since November 15, 1990 (the day the federal Clean Air Act Amendments were adopted) are shown in the tables below.

Facility Emissions Summary
PXP Platform Irene - FID 8016

I. This Projects "I" NEI-90

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr

II. This Facility's "P1s"
Enter all facility "P1" NEI-90s below:

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
AP 11435	03/30/05		1.61										
A 12006	03/31/06	0.07	0.01	0.01	0.00	0.09	0.02	0.11	0.02	0.01	0.00	0.01	0.00
AP 12683	09/25/08			4.70	0.88								
A 13044				0.088	0.016								
Totals		**0.07**	**1.62**	**4.80**	**0.90**	**0.09**	**0.02**	**0.11**	**0.02**	**0.01**	**0.00**	**0.01**	**0.00**

Notes:
(1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

III. This Facility's "P2" NEI-90 Decreases
Enter all facility "P2" NEI-90s below:

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Totals		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes:
(1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

IV. This Facility's Pre-90 "D" Decreases
Enter all facility "D" decreases below:

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Totals		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes:
(1) Facility "D" from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

V. Calculated This Facility's NEI-90
Table below summarizes facility NEI-90 as equal to: I+ (P1-P2) -D

	NOx		ROC		CO		SOx		PM		PM10	
Term	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Project "I"	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P1	0.07	1.62	4.80	0.90	0.09	0.02	0.11	0.02	0.01	0.00	0.01	0.00
P2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FNEI-90	**0.07**	**1.62**	**4.80**	**0.90**	**0.09**	**0.02**	**0.11**	**0.02**	**0.01**	**0.00**	**0.01**	**0.00**

Notes:
(1) Resultant FNEI-90 from above Section I thru IV data.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

Stationary Source NEI-90 Calculations
PXP Point Pedernales Stationary Source

Facility No.	Facility Name	NOx lb/day	NOx ton/yr	ROC lb/day	ROC ton/yr	CO lb/day	CO ton/yr	SOx lb/day	SOx ton/yr	PM lb/day	PM ton/yr	PM10 lb/day	PM10 ton/yr
3069	La Purisima	0.00	0.00	25.47	4.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3095	Lompoc O&G Plant	20.86	2.64	136.98	25.04	12.34	1.98	9.08	0.64	3.10	0.53	3.10	0.53
3309	Jesus Maria "D"	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3310	Orcutt Fee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3802	Eefson Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3832	Jesus Maria "A"	0.00	0.00	2.75	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3837	Lompoc Fee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3839	Hill Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4417	Arkley Fee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4218	Lompoc ICEs	5.04	0.96	0.24	0.05	1.20	0.21	0.48	0.07	0.00	0.00	0.00	0.00
8016	Platform Irene	0.07	1.62	4.80	0.90	0.09	0.02	0.11	0.02	0.01	0.00	0.01	0.00
Totals		**25.97**	**5.22**	**170.23**	**30.83**	**13.63**	**2.21**	**9.67**	**0.73**	**3.11**	**0.53**	**3.11**	**0.53**

Notes:
(1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

Table 5.1-1
PXP Platform Irene - Part70/PTO 9106-R6
Operating Equipment Description

		Device Specifications				Usage Data			Maximum Operating Schedule				
Equipment Categor	**Description**	**Fuel**	**% S**	**Size**	**Units**	**Capacity**	**Units**	**Load**	**hr**	**day**	**qtr**	**year**	**References**
Combustion - Engines	North Crane	D2	0.20	210	bhp	7,143	Btu/bhp-hr	--	1.0	24	730	2,920	A
	South Crane	D2	0.20	197	bhp	7,069	Btu/bhp-hr	--	1.0	24	730	2,920	
	Emergency Generator - Drilling	D2	0.20	1,300	bhp	--	--		1.0	2	200	200	
	Emergency Generator - Drilling	D2	0.20	1,300	bhp	--	--		1.0	2	200	200	
	Emergency Generator - Prod.	D2	0.20	590	bhp	--	--		1.0	2	200	200	
	Emergency Firewater Pump	D2	0.20	420	bhp	--	--		1.0	2	200	200	
Combustion - Flare	Pilot	Propane	0.0796	55	scfh	0.138	MMBtu/hr	--	1.0	24	2,190	8,760	B
	Purge	PG	0.0796	55	scfh	0.072	MMBtu/hr		1.0	24	2,190	8,760	
	Planned - continuous	SG	0.0796	354	scfh	3.101	MMscf/yr	--	1.0	24	0	1	
	Planned - other	PG	0.0796	625	MMBtu/hr	1.699	MMscf/yr	--	--	--	0	1	
	Unplanned	SG	0.3000	625	MMBtu/hr	20.800	MMscf/yr	--	--	--	0	1	
Fugitive Components	Oil - controlled	--	--	4,134	comp-lp	--	--	--	1.0	24	2,190	8,760	C
	Oil - 1/2" SS - controlled	--	--	--		--	--	--					
	Oil - uncontrolled	--	--	0	comp-lp	--	--	--	1.0	24	2,190	8,760	
	Gas - controlled	--	--	7,409	comp-lp	--	--	--	1.0	24	2,190	8,760	
	Gas - 1/2" SS - controlled			--									
	Gas - uncontrolled	--	--	0	comp-lp	--	--	--	1.0	24	2,190	8,760	
Platform Vessels	SB-Main Engines - con	D2	0.20	4,000	bhp-total	0.049	gal/bhp-hr	0.65	1.0	11	275	1,100	D
	SB-Main Engines - unc	D2	0.20	4,000	bhp-total	0.055	gal/bhp-hr	0.65	1.0	11	28	110	
	SB-Auxiliary Engines	D2	0.20	490	bhp-total	0.055	gal/bhp-hr	0.50	1.0	11	275	1,100	
	SB-Bow Thruster	D2	0.20	515	bhp-total	0.055	gal/bhp-hr	1.00	1.0	2	50	200	
	Emergency Response	D2	0.20	4,400	bhp-total	0.055	gal/bhp-hr	0.65	--	--	32	127	
	MOB	G	0.20	80	bhp-total	--	--	0.65	1.0	24	50	200	
	Escape Capsules	G	0.20	116	bhp-total	--	--	0.65	1.0	24	50	200	
Pigging Equipment	Oil Launcher	--	--	32	cf	5	psig	--	1	1	13	52	E
	Gas Launcher	--	--	5	cf	5	psig	--	1	1	46	182	
Sumps/Tanks/ Separators	Sub-deck Sump #A	--	--	6	ft2	--	--	--	1.0	24	2,190	8,760	F
	Sub-deck Sump #B	--	--	18	ft2	--	--	--	1.0	24	2,190	8,760	
	Sub-deck Sump #C	--	--	79	ft2	--	--	--	1.0	24	2,190	8,760	
	Wastewater Tank 530	--	--	79	ft2	--	--	--	1.0	24	2,190	8,760	
	Wastewater Tank 540	--	--	79	ft2	--	--	--	1.0	24	2,190	8,760	
	Roll-Off Bins (4x)	--	--	60	ft2	--	--	--	1.0	24	1,008	3,024	
Solvent Usage	Cleaning/degreasing	--	--	various		various	--	--	1.0	24	2,190	8,760	G

Table 5.1-2
PXP Platform Irene - Part70/PTO 9106-R6
Equipment Emission Factors

Equipment Category	Description	NOx	ROC	CO	SOx	PM	PM10	GHG	Units	References
		Emission Factors								
Combustion - Engines	North Crane	2.446	0.36	0.95	0.20	0.31	0.30	163.60	lb/MMBtu	A
	South Crane	2.471	0.36	0.95	0.20	0.31	0.30	163.60	lb/MMBtu	
	Emergency Generator - Drilling	14.06	1.12	3.03	0.18	0.98	0.98	556.58	g/bhp-hr	
	Emergency Generator - Drilling	14.06	1.12	3.03	0.18	0.98	0.98	556.58	g/bhp-hr	
	Emergency Generator - Prod.	14.06	1.12	3.03	0.18	0.98	0.98	556.58	g/bhp-hr	
	Emergency Firewater Pump	14.06	1.12	3.03	0.18	0.98	0.98	556.58	g/bhp-hr	
Combustion - Flare	Pilot	0.068	0.0054	0.0824	0.102	0.0075	0.0075	117.00	lb/MMBtu	B
	Purge	0.068	0.0054	0.0824	0.102	0.0075	0.0075	117.00	lb/MMBtu	
	Planned - continuous	0.068	0.0054	0.0824	0.102	0.0075	0.0075	117.00	lb/MMBtu	
	Planned - other	0.068	0.0054	0.0824	0.102	0.0075	0.0075	117.00	lb/MMBtu	
	Unplanned	0.068	0.0054	0.0824	0.385	0.0075	0.0075	117.00	lb/MMBtu	
Fugitive Components	Oil - controlled	--	0.0009	--	--	--	--	--	lb/day-clp	C
	Oil - 1/2" SS - controlled									
	Oil - uncontrolled	--	--	--	--	--	--	--	lb/day-clp	
	Gas - controlled	--	0.0147	--	--	--	--	--	lb/day-clp	
	Gas - 1/2" SS - controlled									
	Gas - uncontrolled	--	--	--	--	--	--	--	lb/day-clp	
Platform Vessels	SB-Main Engines - con	270.00	16.80	78.30	28.17	33.00	31.68	22,309.60	lb/1000 gal	D
	SB-Main Engines - unc	561.17	16.80	78.30	28.17	33.00	31.68	22,309.60	lb/1000 gal	
	SB-Auxiliary Engines	600.05	48.98	129.26	28.17	42.18	40.49	22,309.60	lb/1000 gal	
	SB-Bow Thruster	600.05	48.98	129.26	28.17	42.18	40.49	22,309.60	lb/1000 gal	
	Emergency Response	561.17	16.80	78.30	28.17	33.00	31.68	22,309.60	lb/1000 gal	
	MOB	1.08	90.40	212.00	0.27	24.00	24.00	556.58	g/bhp-hr	
	Escape Capsules	1.08	90.40	212.00	0.27	24.00	24.00	556.58	g/bhp-hr	
Pigging Equipment	Oil Launcher	--	0.061	--	--	--	--	--	lb/acf-evnt	E
	Gas Launcher	--	0.028	--	--	--	--	--	lb/acf-evnt	
Sumps/Tanks/Separators	Sub-deck Sump #A	--	0.013	--	--	--	--	--	lb/ft2-day	F
	Sub-deck Sump #B	--	0.013	--	--	--	--	--	lb/ft2-day	
	Sub-deck Sump #C	--	0.013	--	--	--	--	--	lb/ft2-day	
	Wastewater Tank 530	--	0.013	--	--	--	--	--	lb/ft2-day	
	Wastewater Tank 540	--	0.013	--	--	--	--	--	lb/ft2-day	
	Roll-Off Bins (4x)	--	0.097	--	--	--	--	--	lb/ft2-day	
Solvent Usage	Cleaning/degreasing	--	various	--	--	--	--	--	lb/gal	G

Table 5.1-3
PXP Platform Irene - Part70/PTO 9106-R6
Hourly and Daily Emissions

		NOx		ROC		CO		SOx		PM		PM10		GHG	
Equipment Category	**Description**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**
Combustion - Engines	North Crane	3.89	93.34	0.57	13.74	1.51	7.79	0.32	7.79	0.49	11.83	0.47	11.36	245.40	5,889.72
	South Crane	3.65	87.54	0.53	12.75	1.40	7.23	0.30	7.23	0.46	10.98	0.44	10.54	227.83	5,467.88
	Emergency Generator - Drilling	--	80.59	--	6.42	--	17.37	--	1.03	--	5.60	--	5.60	--	3,190.27
	Emergency Generator - Drilling	--	80.59	--	6.42	--	17.37	--	1.03	--	5.60	--	5.60	--	3,190.27
	Emergency Generator - Prod.	--	36.58	--	2.90	--	7.88	--	0.47	--	2.55	--	2.55	--	1,447.89
	Emergency Firewater Pump	--	26.07	--	2.07	--	5.60	--	0.33	--	1.80	--	1.80	--	1,030.70
Combustion - Flare	Pilot	0.01	0.22	0.00	0.02	0.01	0.27	0.01	0.34	0.00	0.02	0.00	0.02	16.09	386.10
	Purge	0.00	0.12	0.00	0.01	0.01	0.14	0.01	0.18	0.00	0.01	0.00	0.01	8.42	202.18
	Planned - continuous	0.03	0.76	0.00	0.06	0.04	0.92	0.05	1.14	0.00	0.08	0.00	0.08	54.59	1,310.13
	Planned - other	--	--	--	--	--	--	--	--	--	--	--	--	--	--
	Unplanned	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive Components	Oil - controlled	--	--	0.16	3.72	--	--	--	--	--	--	--	--	--	--
	Oil - 1/2" SS - controlled														
	Oil - unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--
	Gas - controlled	--	--	4.54	108.91	--	--	--	--	--	--	--	--	--	--
	Gas - 1/2" SS - controlled														
	Gas - unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--
Platform Vessels	SB-Main Engines - con	34.40	378.38	2.14	23.54	9.98	109.73	3.59	39.48	4.20	46.25	4.04	44.40	2,842.24	31,264.67
	SB-Main Engines - unc	80.25	882.72	2.40	26.43	11.20	123.17	4.03	44.31	4.72	51.91	4.53	49.83	3,190.27	35,093.00
	SB-Auxiliary Engines	8.09	88.94	0.66	7.26	1.74	19.16	0.38	4.18	0.57	6.25	0.55	6.00	300.62	3,306.84
	SB - Bow Thruster	17.00	33.99	1.39	2.77	3.66	7.32	0.80	1.60	1.19	2.39	1.15	2.29	631.92	1,263.84
	Emergency Response	--	--	--	--	--	--	--	--	--	--	--	--	--	--
	MOB	--	--	--	--	--	--	--	--	--	--	--	--	--	--
	Escape Capsules	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Pigging Equipment	Oil Launcher	--	--	1.95	1.95	--	--	--	--	--	--	--	--	--	--
	Gas Launcher	--	--	0.14	0.14	--	--	--	--	--	--	--	--	--	--
Sumps/Tanks/Separators	Sub-deck Sump #A	--	--	0.00	0.1	--	--	--	--	--	--	--	--	--	--
	Sub-deck Sump #B	--	--	0.01	0.2	--	--	--	--	--	--	--	--	--	--
	Sub-deck Sump #C	--	--	0.04	1.0	--	--	--	--	--	--	--	--	--	--
	Wastewater Tank 530	--	--	0.010	0.150	--	--	--	--	--	--	--	--	--	--
	Wastewater Tank 540	--	--	0.010	0.150	--	--	--	--	--	--	--	--	--	--
	Roll-Off Bins (4x)	--	--	0.97	23.3	--	--	--	--	--	--	--	--	--	--
Solvent Usage	Cleaning/degreasing	--	--	3.95	31.6	--	--	--	--	--	--	--	--	--	--

Table 5.1-4
PXP Platform Irene - Part70/PTO 9106-R6
Quarterly and Annual Emissions

		NOx		ROC		CO		SOx		PM		PM10		GHG	
Equipment Category	**Description**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**
Combustion - Engines	North Crane	1.42	5.68	0.21	0.84	0.55	2.21	0.12	0.47	0.18	0.72	0.17	0.69	89.57	358.29
	South Crane	1.33	5.33	0.19	0.78	0.51	2.05	0.11	0.44	0.17	0.67	--	0.64	83.16	332.63
	Emergency Generator - Drilling	4.03	4.03	0.32	0.32	0.87	0.87	0.05	0.05	0.28	0.28	0.28	0.28	159.51	159.51
	Emergency Generator - Drilling	4.03	4.03	0.32	0.32	0.87	0.87	0.05	0.05	0.28	0.28	0.28	0.28	159.51	159.51
	Emergency Generator - Prod.	1.83	1.83	0.15	0.15	0.39	0.39	0.02	0.02	0.13	0.13	0.13	0.13	72.39	72.39
	Emergency Firewater Pump	1.30	1.30	0.10	0.10	0.28	0.28	0.02	0.02	0.09	0.09	0.09	0.09	51.54	51.54
Combustion - Flare	Pilot	0.01	0.04	0.00	0.00	0.01	0.05	0.02	0.06	0.00	0.00	0.00	0.00	17.62	70.46
	Purge	0.01	0.02	0.00	0.00	0.01	0.03	0.01	0.03	0.00	0.00	0.00	0.00	9.22	36.90
	Planned - continuous	0.03	0.14	0.00	0.01	0.04	0.17	0.05	0.21	0.00	0.02	0.00	0.02	59.77	239.10
	Planned - other	0.02	0.08	0.00	0.01	0.02	0.09	0.03	0.11	0.00	0.01	0.00	0.01	0.00	0.00
	Unplanned	0.23	0.93	0.02	0.07	0.28	1.13	1.32	5.27	0.03	0.10	0.03	0.10	0.00	0.00
Fugitive Components	Oil - controlled	--	--	0.17	0.68	--	--	--	--	--	--	--	--	--	--
	Oil - 1/2" SS - controlled														
	Oil - unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--
	Gas - controlled	--	--	4.97	19.88	--	--	--	--	--	--	--	--	--	--
	Gas - 1/2" SS - controlled														
	Gas - unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--
Platform Vessels	SB-Main Engines - con	4.73	18.92	0.29	1.18	1.37	5.49	0.49	1.97	0.58	2.31	0.55	2.22	390.81	1,563.23
	SB-Main Engines - unc	1.10	4.41	0.03	0.13	0.15	0.62	0.06	0.22	0.06	0.26	0.06	0.25	43.87	175.47
	SB-Auxiliary Engines	1.11	4.45	0.09	0.36	0.24	0.96	0.05	0.21	0.08	0.31	0.08	0.30	41.34	165.34
	SB-Bow Thruster	0.42	1.70	0.03	0.14	0.09	0.37	0.02	0.08	0.03	0.12	0.03	0.11	15.80	63.19
	Emergency Response	1.40	5.61	0.04	0.17	0.20	0.78	0.07	0.28	0.08	0.33	0.08	0.32	55.71	222.84
	MOB	0.00	0.01	0.26	1.04	0.61	2.43	0.00	0.00	0.07	0.28	0.07	0.28	1.60	6.38
	Escape Capsules	0.00	0.02	0.38	1.50	0.88	3.53	0.00	0.00	0.10	0.40	0.10	0.40	2.31	9.25
Pigging Equipment	Oil Launcher	--	--	0.01	0.1	--	--	--	--	--	--	--	--	--	--
	Gas Launcher	--	--	0.00	0.0	--	--	--	--	--	--	--	--	--	--
Sumps/Tanks/Separator	Sub-deck Sump #A	--	--	0.00	0.01	--	--	--	--	--	--	--	--	--	--
	Sub-deck Sump #B	--	--	0.01	0.04	--	--	--	--	--	--	--	--	--	--
	Sub-deck Sump #C	--	--	0.05	0.19	--	--	--	--	--	--	--	--	--	--
	Wastewater Tank 530	--	--	0.010	0.030	--	--	--	--	--	--	--	--	--	--
	Wastewater Tank 540	--	--	0.010	0.030	--	--	--	--	--	--	--	--	--	--
	Roll-Off Bins (4x)	--	--	0.49	1.47	--	--	--	--	--	--	--	--	--	--
Solvent Usage	Cleaning/degreasing	--	--	0.62	2.47	--	--	--	--	--	--	--	--	--	--

Table 5.2
PXP Platform Irene - Part70/PTO 9106-R6
Total Permitted Facility Emissions

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	7.54	1.10	2.91	0.63	0.95	0.91	473.23
Combustion - Flare	0.04	0.00	0.05	0.06	0.00	0.00	70.68
Fugitive Components	--	4.69	--	--	--	--	--
Supply Boat (25-mile)	88.33	3.06	12.94	4.41	5.29	5.08	3,490.89
Emergency Response	--	--	--	--	--	--	--
MOB	--	--	--	--	--	--	--
Escape Capsules	--	--	--	--	--	--	--
Pigging	--	2.09	--	--	--	--	--
Sumps/Tanks/Separators	--	0.08	--	--	--	--	--
Solvent Usage	--	3.95	--	--	--	--	--
Total	95.91	14.98	15.90	5.10	6.24	5.99	4,034.80

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	404.70	44.30	63.23	17.90	38.40	37.45	11,357.59
Combustion - Flare	0.99	0.08	1.19	1.48	0.11	0.11	1,696.23
Fugitive Components	--	112.63	--	--	--	--	
Supply Boat (25-mile)	1,005.65	36.46	149.65	50.09	60.55	58.13	39,663.68
Emergency Response	--	--	--	--	--	--	--
MOB	--	--	--	--	--	--	--
Escape Capsules	--	--	--	--	--	--	--
Pigging	--	2.09	--	--	--	--	--
Sumps/Tanks/Separators	--	1.64	--	--	--	--	--
Solvent Usage	--	31.60	--	--	--	--	--
Total	1,411.34	228.80	214.07	69.47	99.06	95.69	52,717.51

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	13.94	1.29	3.47	0.37	1.13	0.95	615.69
Combustion - Flare	0.30	0.02	0.37	1.42	0.03	0.03	86.61
Fugitive Components	--	5.14	--	--	--	--	--
Supply Boat (25-mile)	7.37	0.45	1.86	0.62	0.75	0.72	491.81
Emergency Response	1.40	0.04	0.20	0.07	0.08	0.08	55.71
MOB	0.00	0.26	0.61	0.00	0.07	0.07	1.60
Escape Capsules	0.00	0.38	0.88	0.00	0.10	0.10	2.31
Pigging	--	0.02	--	--	--	--	--
Sumps/Tanks/Separators	--	0.08	--	--	--	--	--
Solvent Usage	--	0.62	--	--	--	--	--
Total	23.02	8.30	7.38	2.48	2.16	1.95	1,253.73

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	22.19	2.50	6.66	1.05	2.17	2.11	1,133.88
Combustion - Flare	1.21	0.10	1.47	5.69	0.13	0.13	346.46
Fugitive Components	--	20.56	--	--	--	--	--
Supply Boat (25-mile)	29.48	1.81	7.43	2.48	3.00	2.88	1,967.23
Emergency Response	5.61	0.17	0.78	0.28	0.33	0.32	222.84
MOB	0.01	1.04	2.43	0.00	0.28	0.28	6.38
Escape Capsules	0.02	1.50	3.53	0.00	0.40	0.40	9.25
Pigging	--	0.06	--	--	--	--	--
Sumps/Tanks/Separators	--	0.30	--	--	--	--	--
Solvent Usage	--	2.47	--	--	--	--	--
Total	58.52	30.51	22.29	9.52	6.31	6.12	3,686.04

Table 5.3
PXP Platform Irene - Part70/PTO 9106-R6
Federal Potential to Emit

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	7.54	1.10	2.91	0.63	0.95	0.91	473.23
Combustion - Flare	0.04	0.00	0.05	0.06	0.00	0.00	70.68
Fugitive Components	--	--	--	--	--	--	--
Supply Boat (25-mile)	88.33	3.06	12.94	4.41	5.29	5.08	3,490.89
Emergency Response	--	--	--	--	--	--	--
MOB	--	--	--	--	--	--	--
Escape Capsules	--	--	--	--	--	--	--
Pigging	--	2.09	--	--	--	--	--
Sumps/Tanks/Separators	--	0.08	--	--	--	--	--
Solvent Usage	--	3.95	--	--	--	--	--
Total	95.91	10.29	15.90	5.10	6.24	5.99	4,034.80

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	404.70	44.30	63.23	17.90	38.40	37.45	11,357.59
Combustion - Flare	0.99	0.08	0.90	1.48	0.11	0.11	1,696.23
Fugitive Components	--	--	--	--	--	--	--
Supply Boat (25-mile)	1,005.65	36.46	149.65	50.09	60.55	58.13	39,663.68
Emergency Response	--	--	--	--	--	--	--
MOB	--	--	--	--	--	--	--
Escape Capsules	--	--	--	--	--	--	--
Pigging	--	2.09	--	--	--	--	--
Sumps/Tanks/Separators	--	1.64	--	--	--	--	--
Solvent Usage	--	31.60	--	--	--	--	--
Total	1,411.34	116.17	213.78	69.47	99.06	95.69	52,717.51

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	13.94	1.29	3.47	0.37	1.13	0.95	615.69
Combustion - Flare	0.30	0.02	0.37	1.42	0.03	0.03	86.61
Fugitive Components	--	--	--	--	--	--	--
Supply Boat (25-mile)	7.37	0.45	1.86	0.62	0.75	0.72	491.81
Emergency Response	1.40	0.04	0.20	0.07	0.08	0.08	55.71
MOB	0.00	0.26	0.61	0.00	0.07	0.07	1.60
Escape Capsules	0.00	0.38	0.88	0.00	0.10	0.10	2.31
Pigging	--	0.02	--	--	--	--	--
Sumps/Tanks/Separators	--	0.08	--	--	--	--	--
Solvent Usage	--	0.62	--	--	--	--	--
Total	23.02	3.16	7.38	2.49	2.17	1.95	1,253.73

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	22.19	2.50	6.66	1.05	2.17	2.11	1,133.88
Combustion - Flare	1.21	0.10	1.47	5.69	0.13	0.13	346.46
Fugitive Components	--	--	--	--	--	--	--
Supply Boat (25-mile)	29.48	1.81	7.43	2.48	3.00	2.88	1,967.23
Emergency Response	5.61	0.17	0.78	0.28	0.33	0.32	222.84
MOB	0.01	1.04	2.43	0.07	0.28	0.28	6.38
Escape Capsules	0.02	1.50	3.53	0.10	0.40	0.40	9.25
Pigging	--	0.06	--	--	--	--	--
Sumps/Tanks/Separators	--	0.30	--	--	--	--	--
Solvent Usage	--	2.47	--	--	--	--	--
Total	58.51	9.95	22.29	9.67	6.31	6.12	3,686.04

Table 5.4
PXP Platform Irene - Part70/PTO 9106-R6
Estimated Permit Exempt Emissions

A. QUARTERLY (tpq)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Helicopters	1.05	0.88	0.65	0.06	0.05	0.05
Diesel Storage Tanks	--	0.01	--	--	--	--
Surface Coating - Maintenance	--	0.13	--	--	--	--
	1.05	1.02	0.65	0.06	0.05	0.05

B. ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Helicopters	4.22	3.52	2.58	0.24	0.19	0.19
Diesel Storage Tanks	--	0.05	--	--	--	--
Surface Coating - Maintenance	--	0.13	--	--	--	--
	4.22	3.70	2.58	0.24	0.19	0.19

6.0 Air Quality Impact Analyses

6.1 *Modeling*

Air quality modeling was not required for the issuance of this OCS operating permit. Modeling was performed for PXP's onshore portion of the Point Pedernales Project in 1988. The air impacts from the operation of Platform Irene were addressed in ATC 6708 and the results summarized in PTO 6708.

6.2 *Increments*

An air quality increment analysis was not required for the issuance of this OCS permit. An increment analysis was performed for PXP's onshore portion of the Point Pedernales Project in 1988. The air impacts from the operation of Platform Irene were addressed in ATC 6708 and the results summarized in PTO 6708.

6.3 *Monitoring*

Air quality monitoring is not required for the issuance of this OCS permit.

6.4 *Health Risk Assessment*

A Health Risk Assessment was not required for this OCS permit.

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 *General*

Santa Barbara County is in attainment of the federal ozone standard but is in nonattainment of the state eight-hour ozone ambient air quality standard. In addition, the County is in nonattainment of the state PM_{10} ambient air quality standards. The County is either in attainment or unclassified with respect to all other ambient air quality standards. Therefore, emissions from all emission units at the stationary source and its constituent facilities must be consistent with the provisions of the USEPA and State approved Clean Air Plans (CAP) and must not interfere with maintenance of the federal ambient air quality standards and progress towards attainment of the state ambient air quality standards. Under District regulations, any modifications at this stationary source that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Additional increases may trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 55 lbs/day for all non-attainment pollutants except PM_{10} for which the level is 80 lbs/day.

7.2 *Clean Air Plan*

The 2007 Clean Air Plan, adopted by the District Board on August 16, 2007, addressed both federal and state requirements, serving as the maintenance plan for the federal eight-hour ozone standard and as the state triennial update required by the Health and Safety Code to demonstrate how the District will expedite attainment of the state eight-hour ozone standard. The plan was developed for Santa Barbara County as required by both the 1998 California Clean Air Act and the 1990 Federal Clean Air Act Amendments.

On January 20, 2011 the District Board adopted the 2010 Clean Air Plan. The 2010 Plan provides a three-year update to the 2007 Clean Air Plan. As Santa Barbara County has yet to attain the state eight-hour ozone standard, the 2010 Clean Air Plan demonstrates how the District plans to attain that standard. The 2010 Clean Air Plan therefore satisfies all state triennial planning requirements.

7.3 Offset Requirements

Increases in county-wide emissions from a new project, that are above applicable thresholds, must be offset by reductions in emissions from another county source. District rules require existing source emission reductions to be in place prior to the initiation of and for the duration of the project's emissions. The emission reductions must be real, quantifiable, surplus, permanent and enforceable. For permitted offset sources, a modification of existing permits is required to ensure that emission reductions will occur. For sources that are not owned or operated by the project applicant, a written agreement between the owner of the emission reduction source and the project applicant, with the District as third beneficiary, is required.

The OCS air regulation, 40 C.F.R. Part 55, did not require existing sources to provide emission offsets however, agreements between the District and PXP related to the permitting of the onshore processing facilities have required PXP to offset emissions associated with onshore facility as well as the emissions generated by the OCS platforms. OCS emissions of NO_x and ROC emissions were offset at a minimum ratio of 1:1.

PXP entered into an agreement with the District identifying the sources of the emission reduction credits provided as offsets for the Point Pedernales Project, including Platform Irene. This August 1986 *Emission Reduction Agreement - Union Oil Point Pedernales Project* was amended on November 18, 1996 to reflect use of the Battles Gas Plant shutdown credits. This agreement is located the Point Pedernales project file.

Since the previous permit renewal, the installation of the freewater knock out vessel required emission offsets. These are the subject of permit condition 9.C.14 and Table 7.0.

TABLE 7.0 ROC EMISSIONS AND OFFSETS

REACTIVE ORGANIC COMPOUNDS (ROC)

PROJECT EMISSIONS	TPQ	TPY
Net Emissions Increase (NEI) Liability (Installation of FWKO)	0.22	0.88

EMISSION REDUCTION SOURCES[4]	Emission Reductions TPQ	Emission Reductions TPY	Distance Factor[1]	Offset Credit TPQ	Offset Credit TPY
ERC Certificate 0141-1108	0.05	0.20	1.5	0.03	0.13
ERC Certificate 0153-0812	0.28	1.12	1.5	0.19	0.75
TOTAL ROC	0.33	1.32		0.22	0.88

Notes:

1. Point Pedernales stationary source triggers APCD offset requirements. ERCs associated with each certificate are in North county > 7.5 miles from Platfrom Irene.

8.0 Lead Agency Permit Consistency

A Final Development Plan for the Point Pedernales Project (#85-DP-71) was approved by the Santa Barbara Planning Commission on May 13, 1986. This Plan included permit conditions E-6, E-9 and E-10 which requires PXP to fully mitigate adverse air quality impacts of the project which would affect the county. In part, these conditions required the following measures: full mitigation of all NO_x and ROC construction and operation emissions associated with the Point Pedernales Project (including OCS emission sources); installation of Ambient Air Monitoring and Continuous Emission Monitoring Stations, and submittal of an air quality related Emergency Episode Plan. PXP and the County entered into a legally binding contract outlining the implementation of these conditions.

The United States Department of Interior's Minerals Management Service approved the *Plan of Development* for PXP's Platform Irene on August 5, 1985.

This permit renewal is exempt from CEQA review.

9.0 Permit Conditions

This section lists the applicable permit conditions for Platform Irene. Section A lists the standard administrative conditions. Section B lists 'generic' permit conditions, including emission standards, for all equipment in this permit. Section C lists conditions affecting specific equipment. Conditions listed in Sections A, B and C are enforceable by the USEPA, the District, the State of California and the public. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable. In case of a discrepancy between the wording of a condition and the applicable federal or District rule(s), the wording of the rule shall control.

For the purposes of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this permit, nothing in the permit shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

9.A Standard Administrative Conditions

The following federally-enforceable administrative permit conditions apply to Platform Irene:

A.1 **Condition Acceptance.** Acceptance of this operating permit by PXP shall be considered as acceptance of all terms, conditions, and limits of this permit. *[Ref: PTO 9106]*

A.2 **Defense of Permit.** PXP agrees, as a condition of the issuance and use of this PTO, to defend at its sole expense any action brought against the APCD because of issuance of this permit. PXP shall reimburse the APCD for any and all costs including, but not limited to, court costs and attorney's fees which the APCD may be required by a court to pay as a result of such action. The APCD may, at its sole discretion, participate in the defense of any such action, but such participation shall not relieve PXP of its obligation under this condition. The APCD shall bear its

own expenses for its participation in the action.
[Ref: PTO 9106]

A.3 **Reimbursement of Costs.** All reasonable expenses, as defined in District Rule 210, incurred by the District, District contractors, and legal counsel for the activities listed below that follow the issuance of this permit, including but not limited to permit condition implementation, compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by the permittee as required by Rule 210. Reimbursable activities include work involving: permitting, compliance, CEMS, modeling/AQIA, ambient air monitoring and air toxics. *[Ref: PTO 9106, District Rule 210]*

A.4 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the District or its agents, the permittee shall make such records available or provide access to such facilities upon notice from the District. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. *[Ref: PTO 9106]*

A.5 **Compliance.** Nothing contained within this permit shall be construed as allowing the violation of any local, state or federal rules, regulations, air quality standards or increments. *[Ref: PTO 9106]*

A.6 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application and supplements thereof (as documented in the District's project file) and the District's analyses under which this permit is issued as documented in the Permit Analyses prepared for and issued with the permit.

Prior to the drilling of any wells on Platform Irene which exceed the full development scenario of forty-three (43) wells as evaluated in the EIS/EIR, or the installation of any future platforms that will produce oil and gas to be processed by any facilities permitted herein, PXP shall apply to the District for a modification of this permit and shall demonstrate that the proposed operations will not cause or contribute to the violation of any air quality standard, or interfere with the attainment or maintenance of air quality standards.
[Ref: ATC 9612]

A.7 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on the Point Pedernales Project by:

(a) the County of Santa Barbara in Final Development Plan Permit 85-DP-71, the August 1986 *Emission Reduction Agreement - Union Oil Point Pedernales Project* and any subsequent modifications to these documents;

(b) the Santa Barbara County Air Pollution Control District in Authority to Construct No. 6708, Permit to Operate No. 6708, and any subsequent modifications to either permit; and

(c) the California Coastal Commission in the consistency determination for the Project with the California Coastal Act. *[Ref: PTO 9106]*

A.8 **Compliance with Department of Interior Permits.** PXP shall comply with all air quality control requirements imposed by the Department of the Interior in the *Plan of Development* approved for Platform Irene on August 5, 1995 and any subsequent modifications. Such requirements shall be enforceable by the District. *[Ref: PTO 9106]*

A.9 **Compliance with Permit Conditions.**

(a) The permittee shall comply with all permit conditions in Sections 9.A, 9.B and 9.C.

(b) This permit does not convey property rights or exclusive privilege of any sort.

(c) Any permit noncompliance with sections 9.A, 9.B, or 9.C constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(d) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(e) A pending permit action or notification of anticipated noncompliance does not stay any permit condition.

(f) Within a reasonable time period, the permittee shall furnish any information requested by the Control Officer, in writing, for the purpose of determining:

(i) compliance with the permit, or
(ii) whether or not cause exists to modify, revoke and reissue, or terminate a permit or for an enforcement action.

(g) In the event that any condition herein is determined to be in conflict with any other condition contained herein, then, if principles of law do not provide to the contrary, the condition most protective of air quality and public health and safety shall prevail to the extent feasible. *[Ref: 40 CFR Part 70.6.(a)(6), District Rules 1303.D.1]*

A.10 **Emergency Provisions.** The permittee shall comply with the requirements of the District, Rule 505 (Upset/Breakdown rule) and/or District Rule 1303.F, whichever is applicable to the emergency situation. In order to maintain an affirmative defense under Rule 1303.F, the permittee shall provide the District, in writing, a "notice of emergency" within 2 working days of the emergency. The "notice of emergency" shall contain the information/documentation listed in Sections (1) through (5) of Rule 1303.F. *[Re: 40 CFR 70.6(g), District Rule 1303.F]*

A.11 **Compliance Plan.**

(a) The permittee shall comply with all federally enforceable requirements that become applicable during the permit term in a timely manner.
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(b) For all applicable equipment, the permittee shall implement and comply with any specific compliance plan required under any federally-enforceable rules or standards. *[Ref: District Rule 1302.D.2]*

A.12 **Right of Entry.** The Regional Administrator of USEPA, the Control Officer, or their authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises where a Part 70 Source is located or where records must be kept:

(a) To inspect the stationary source, including monitoring and control equipment, work practices, operations, and emission-related activity;

(b) To inspect and duplicate, at reasonable times, records required by this Permit to Operate;

(c) To sample substances or monitor emissions from the source or assess other parameters to assure compliance with the permit or applicable requirements, at reasonable times. Monitoring of emissions can include source testing. *[Ref: District Rule 1303.D.2]*

A.13 **Severability.** In the event that any condition herein is determined to be invalid, all other conditions shall remain in force. *[Ref: APCD Rules 103 and 1303.D.1]*

A.14 **Permit Life.** The Part 70 permit shall become invalid three years from the date of issuance unless a timely and complete renewal application is submitted to the District. Any operation of the source to which this Part 70 permit is issued beyond the expiration date of this Part 70 permit and without a valid Part 70 operating permit (or a complete Part 70 permit renewal application) shall be a violation of the CAAA, § 502(a) and 503(d) and of the District rules.

The permittee shall apply for renewal of the Part 70 permit no later than 180-days before the date this permit expires. Upon submittal of a timely and complete renewal application, the Part 70 permit shall remain in effect until the Control Officer issues or denies the renewal application. *[Ref: District Rule 1304.D.1]*

A.15 **Payment of Fees.** The permittee shall reimburse the District for all its Part 70 permit processing and compliance expenses for the stationary source on a timely basis. Failure to reimburse on a timely basis shall be a violation of this permit and of applicable requirements and can result in forfeiture of the Part 70 permit. Operation without a Part 70 permit subjects the source to potential enforcement action by the District and the USEPA pursuant to section 502(a) of the Clean Air Act.
[Re: District Rules 1303.D.1 and 1304.D.11, 40 CFR 70.6(a)(7)]

A.16 **Prompt Reporting of Deviations.** The permittee shall submit a written report to the District documenting each and every deviation from the requirements of this permit or any applicable federal requirements within 7 days after discovery of the violation, but not later than 180-days after the date of occurrence. The report shall clearly document, 1) the probable cause and extent of the deviation 2) equipment involved, 3) the quantity of excess pollutant emissions, if any, and 4) actions taken to correct the deviation. The requirements of this condition shall not apply to deviations reported to District in accordance with Rule 505. *Breakdown Conditions*, or Rule 1303.F *Emergency Provisions*. [District Rule 1303.D.1, 40 CFR 70.6(a) (3)]

A.17 **Reporting Requirements/Compliance Certification.** The permittee shall submit compliance certification reports to the USEPA and the Control Officer every six months. These reports shall be submitted on District forms and shall identify each applicable requirement/condition of the permit, the compliance status with each requirement/condition, the monitoring methods used to determine compliance, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations (excluding emergency upsets) from permit requirement. The reporting periods shall be each half of the calendar year,

e.g., January through June for the first half of the year. These reports shall be submitted by September 1 and March 1, respectively, each year. Supporting monitoring data shall be submitted in accordance with the "Semi-Annual Compliance Verification Report" condition in section 9.C. The permittee shall include a written statement from the responsible official, which certifies the truth, accuracy, and completeness of the reports.
[Re: District Rules 1303.D.1, 1302.D.3, 1303.2.c]

A.18 **Federally-enforceable Conditions.** Each federally enforceable condition in this permit shall be enforceable by the USEPA and members of the public. The conditions in the District-only enforceable section of this permit are not federally enforceable or subject to the public/USEPA review. *[Ref: CAAA, § 502(b)(6), 40 CFR 70.6(b)]*

A.19 **Recordkeeping Requirements**. The permittee shall maintain records of required monitoring information that include the following:

(a) The date, place as defined in the permit, and time of sampling or measurements;
(b) The date(s) analyses were performed;
(c) The company or entity that performed the analyses;
(d) The analytical techniques or methods used;
(e) The results of such analyses; and
(f) The operating conditions as existing at the time of sampling or measurement;

The records (electronic or hard copy), as well as all supporting information including calibration and maintenance records, shall be maintained for a minimum of five (5) years from date of initial entry by the permittee and shall be made available to the District upon request. *[Ref: District Rule 1303.D.1.f, 40 CFR 70.6(a)(3)(ii)(A)]*

A.20 **Conditions for Permit Reopening.** The permit shall be reopened and revised for cause under any of the following circumstances:

(a) Additional Requirements: If additional applicable requirements (e.g., NSPS or MACT) become applicable to the source which has an unexpired permit term of three (3) or more years, the permit shall be reopened. Such a reopening shall be completed no later than 18 months after promulgation of the applicable requirement. However, no such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended. All such re-openings shall be initiated only after a 30-day notice of intent to reopen the permit has been provided to the permittee, except that a shorter notice may be given in case of an emergency.

(b) Inaccurate Permit Provisions: If the District or the USEPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

(c) Applicable Requirement: If the District or the USEPA determines that the permit must be revised or revoked to assure compliance with any applicable requirement including a federally enforceable requirement, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

Administrative procedures to reopen a permit shall follow the same procedures as apply to initial permit issuance. Re-openings shall affect only those parts of the permit for which cause to reopen exists. If the permit is reopened, and revised, it will be reissued with the expiration date that was listed in the permit before the re-opening. *[Ref: 40 CFR 70.7(f), 40 CFR 70.6(a)]*

9.B. Generic Conditions

The generic conditions listed below apply to all emission units, regardless of their category or emission rates. These conditions are federally enforceable. Compliance with these requirements is discussed in Section 3. In case of a discrepancy between the wording of a condition and the applicable federal or District rule(s), the wording of the rule shall control.

B.1 **Circumvention (Rule 301).** A person shall not build, erect, install, or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of Division 26 (Air Resources) of the Health and Safety Code of the State of California or of these Rules and Regulations. This Rule shall not apply to cases in which the only violation involved is of Section 41700 of the Health and Safety Code of the State of California, or of District Rule 303. *[Ref: District Rule 301]*

B.2 **Visible Emissions (Rule 302).** PXP shall not discharge into the atmosphere from any single source of emission any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated as No. 1 on the Ringlemann Chart, as published by the United States Bureau of Mines, or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subsection B.2(a) above.

For the equipment listed below, PXP shall determine compliance with this Condition as specified below:

Offshore Flaring

Offshore Flaring: For planned flaring (other than purge and pilot and planned continuous as per Table 5.1-1 of this permit), a visible emissions inspection for a one-minute period shall be performed once per quarter during a planned flaring event. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. If visible emissions are detected during the quarterly inspection, then a USEPA Method 9 visible emission evaluation (VEE) shall immediately be performed for a six-minute period or the duration of the flaring event, whichever is shorter. PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. *[Re: District Rule 302]*

Diesel Fueled IC Engines

Once per calendar quarter, PXP shall perform a visible emissions inspection for a one-minute period on each engine when operating. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. If an engine does not operate during a calendar quarter, no monitoring is required. If visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluations (VEE) shall immediately be performed for a six-minute period. PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected.

Offshore Platform Crane.

During biennial source testing of a crane, PXP shall perform a visible emissions inspection on the crane for a one-minute period. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. If visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluation (VEE) shall immediately be performed for a six-minute period. PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. *[Ref: District Rule 302]*.

B.3 **PM Concentration - Northern Zone (Rule 304).** PXP shall not discharge into the atmosphere, from any source, particulate matter in excess of 0.3 grain per cubic foot of gas at standard conditions. *[Ref: District Rule 304]*

B.4 **Specific Contaminants (Rule 309).** PXP shall not discharge into the atmosphere from any single source sulfur compounds, carbon monoxide and combustion contaminants in excess of the applicable standards listed in Sections A, E and G of Rule 309. *[Ref: District Rule 309]*. {Note: carbon monoxide is not applicable to northern zone}

B.5 **Odorous Organic Sulfides (Rule 310).** PXP shall not discharge into atmosphere H_2S and organic sulfides that result in a ground level impact beyond the PXP property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. *[Re: District Rule 310]*

B.6 **Sulfur Content of Fuels (Rule 311).** PXP shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 796 ppmvd or 50 gr/100 scf (calculated as H_2S) for gaseous fuel. The only natural gas fuel used on Platform Irene is for purge and pilot. Daily Draeger samples are used to determine compliance with this condition.
[Ref: District Rule 311]

B.7 **Organic Solvents (Rule 317).** PXP shall comply with the emission standards listed in Section B of Rule 317. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit. *[Ref: District Rule 317 B.9]*

B.8 **Metal Surface Coating Thinner and Reducer (Rule 322).** The use of photochemically reactive solvents as thinners or reducers in metal surface coatings is prohibited. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit and facility inspections. *[Ref: District Rule 322]*

B.9 **Architectural Coatings (Rule 323).** PXP shall comply with the coating ROC content and handling standards listed in Section D of Rule 323 as well as the Administrative requirements listed in Section F of Rule 323. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit and facility inspections.
[Ref: District Rules 323, 317, 322, 324]

B.10 **Disposal and Evaporation of Solvents (Rule 324).** PXP shall not dispose through atmospheric evaporation of more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit and facility inspections.
[Ref: District Rule 324]

B.11 **Continuous Emissions Monitoring (Rule 328).** PXP shall comply with the requirements of Section C, F, G, H and I of Rule 328. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit as well as on-site inspections.
[Ref: District Rule 328]

B.12 **Adhesives and Sealants (Rule 353).** The permittee shall not use adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers, unless the permittee complies with the following:

(a) Such materials used are purchased or supplied by the manufacturer or suppliers in containers of 16 fluid ounces or less; or alternately

(a) When the permittee uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353, Section B.1, the total reactive organic compound emissions from the use of such material shall not exceed 200 pounds per year unless the substances used and the operational methods comply with Sections D, E, F, G, and H of Rule 353. Compliance shall be demonstrated by recordkeeping in accordance with Section B.2 and/or Section O of Rule 353. *[Re: District Rule 353]*

B.13 **Emergency Episode Plan**. During emergency episodes, PXP shall implement the Emergency Episode Plan approved District on December 12, 2000.

B.14 **Oil and Natural Gas Production MACT.** PXP shall comply with the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage (promulgated June 17, 1999). At a minimum, PXP shall maintain records in accordance with 40 CFR Part 63, Subpart A, Section 63.10(b) (1) and (3). *[40 CFR 63, Sub Report HH]*

B.15 **Reciprocating Internal Combustion Engine NESHAP.** PXP shall comply with the requirements of the RICE NESHAP by the dates specified in the regulation. Prior to making any physical or operational changes to the engines subject to this regulation, PXP shall obtain an Authority to Construct from the District. [*Re:* 40 CFR 63, Subpart ZZZZ]

9.C Requirements and Equipment Specific Conditions

This section includes non-generic federally-enforceable conditions, including emissions and operations limits, monitoring, recordkeeping and reporting are included in this section for each specific equipment group. This section may also contain other non-generic conditions.

C.1 **Internal Combustion Engines.** The following equipment are included in this emissions unit category:

District Device No.	Name
5083	South Crane (197 bhp, DD 6-71N)
5082	North Crane (210 bhp, DD 6-71N)

(a) Emission Limits: Mass emissions from the North and South Crane IC engines listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. In addition, the following specific emission limits apply:

(i) *North and South Crane Engines.* Controlled emissions of NOX from the Pedestal Crane engines shall not exceed either 8.4 g/bhp-hr or 797 ppmv at 15 percent oxygen or 2,400 ppmv at 3 percent oxygen. Compliance shall be based on quarterly or more frequent portable analyzer inspections in accordance with Rule 333. F, and biennial source testing in accordance with Rule 333.I. After June 19, 2010 emissions from the crane engines shall not exceed any of the following:

NOx - 700 ppmv at 15% O2, ROC - 750 ppmv at 15% O2, CO - 4,500 ppmv at 15% O2.

(b) Operational Limits: The following operational limits apply to these IC engines:

(i) *Liquid Fuel Sulfur Limit*. Diesel fuel used by all IC engines shall have a sulfur content no greater than 0.0015 weight percent as determined by District-approved ASTM methods.

(ii) *Operating Limits*. PXP shall comply with the following operating limits:

- The North crane engine shall not use more than: 276 gallons per day; 8,399 gallons per quarter; 33,595 gallons per year of diesel fuel.
- The South crane engine shall not use more than: 256 gallons per day; 7,797 gallons per quarter; 31,189 gallons per year of diesel fuel.

(iii) *Engine Maintenance - North Crane (ID 5082) and West Crane (ID 5083)* - Existing non-emergency non-black start compression ignition reciprocating internal combustion engines (RICE) must comply with the following operating limits by no later than May 3, 2013:

(1) Change the oil and filter every 1,000 hours of operation or annually, whichever comes first. In place of changing the oil every 1,000 hours of operation or annually, the operator may analyze the oil of each engine every 1,000 hours of operation or annually, whichever occurs first. The analysis shall measure the Total Base Number, the oil viscosity, and the percent water content. The oil and filter shall be changed if any of the following limits are exceeded:

(a) The tested Total Base Number is less than 30 percent of the Total Base Number of the oil when new.

(b) The tested oil viscosity has changed by more than 20 percent from the oil viscosity when new.

(c) The tested percent water content (by volume) is greater than 0.5 percent. [*ref: 40 CFR §63.6625*]

(2) Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first.

(3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

(iv) *Engine Identification and Maintenance*. Each IC engine shall be identified with a permanently-affixed plate, tag or marking, referencing either: (i) the IC engine's make, model, serial number, rated BHP and corresponding RPM; or (ii) the operator's unique tag number. The tag shall be made accessible and legible to facilitate District inspection of the IC engine.

(v) *High Pressure Fuel Injectors*. If high pressure fuel injectors are used to comply with Rule 333 standards, then that injector type shall be used on the engine for the life of the engine except as noted below. PXP may revert to the normal pressure fuel injectors if District-approved source testing shows that the Rule 333 standards are achieved.

(c) Monitoring: The following source testing and periodic monitoring conditions apply to the North and South Crane IC engines:

(i) *Inspection and Maintenance Plan (I&M Plan)*. PXP shall implement quarterly inspections on each crane engine according to the District-*approved Engine Inspection and Maintenance Plan* consistent with the requirements of Rule 333, Section F. This Plan, and any subsequent District-approved revisions, is incorporated by reference as an enforceable part of this permit.

(ii) S*ource Testing*. PXP shall perform source testing on each crane engine for the air emissions and process parameters listed in Table 4.1 (Source Test Requirements) in accordance with the requirements of Rule 333, Section I. PXP shall adhere to the source testing permit condition listed below.

(iii) The daily, quarterly and annual hours of operation for each pedestal crane.

(iv) *Diesel Fuel Data*. PXP shall maintain documentation of the sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers.

(d) Recordkeeping: PXP shall keep the required logs, as applicable to this permit, which demonstrate compliance with emission limits, operation limits and monitoring requirements above. All logs shall be available to the District upon request. Written information (logs) shall include:

(i) Daily, quarterly and annual fuel usage in units of gallons for the North and South Crane engines or the daily, quarterly and annual hours of operation.

(ii) The sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers. On an annual basis, the heating value of the diesel fuel (Btu/gal) shall be recorded. The billing vouchers shall be attached to the log.

(iii) IC engine operations logs including quarterly portable analyzer inspection results, consistent with the requirements of Rule 333.J. and the results of the quarterly one-minute visible emissions inspections required by permit condition 9.B.2.

(iv) If an operator's tag number is used in lieu of an IC engine identification plate, documentation which references the operator's unique IC engine ID number to a list containing the make, model, serial number, rated maximum BHP and the corresponding RPM.

(v) Starting May 3, 2013, the following records shall be kept for each engine subject to Subpart ZZZZ:

(1) The date of each engine oil change, the number of hours of operation since the last oil change.

(2) The date and results of each oil analysis if the results of the oil analysis were used as the basis for not changing the oil every 1,000 hours or annually, whichever came first.

(3) The date of each engine air filter inspection and the number of hours of operation since the last air filter inspection. Indicate if the air filter was replaced as a result of the inspection.

(4) The date of each engine’s hose and belts inspection and the number of hours of operation since the last hose and belt inspection. Indicate if any hose or belt was replaced as a result of the inspection.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month’s activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report)*.
(*Re: District Rules 202, 333, 1303, PTO 9106, 40 CFR 70.6*)

C.2 **Combustion Equipment - Flare.** The following equipment is included in this emissions unit category:

Device No.	Name
114005	Flare Relief System (625 MMBtu/hr)

(a) Emission Limits: Mass emissions from the flare relief system listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(b) Operational Limits:

(i) *Flaring Volumes.* Flaring volumes from the purge and pilot, planned continuous and unplanned events shall not exceed the volumes in Table 5.1-1.

(ii) *Flare Gas Sulfur Limit.* The sulfur content of produced gas combusted in the flare during planned flaring events shall not exceed 50 gr/100 scf (796 ppmv) total sulfur calculated as hydrogen sulfide at standard conditions. Compliance shall be based on an in-line continuous hydrogen sulfide analyzer for all planned flaring events, except for purge/pilot gas. Planned flaring is defined in District Rule 359. This analyzer shall be operated consistent with the requirements of the District's CEM Protocol document (dated October 22, 1992 and subsequent updates), where applicable. The readings from this analyzer shall be adjusted upward to take into account the average non-hydrogen sulfide reduced sulfur compounds in the fuel gas (if any) as specified in the District-approved *Flare Gas Sulfur Reporting Plan*.

The sulfur composition of pilot gas shall be determined daily via the use of gas detector tubes (or District-approved equivalent). PXP shall perform additional testing of the sulfur content for planned flaring events, using approved test methods, as requested by the District.

(iii) *Use of Propane as Flare Fuel Gas.* Propane may be used continuously as flare pilot fuel gas. The propane shall meet Gas Processors Association specifications for propane or HD-5 and shall have a total sulfur content no greater than 50 gr/100 scf (796 ppmv). PXP shall record in a log each usage of propane in a District-approved format and shall maintain documentation of the sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers.

(iv) *Planned Flaring - Gas Sweetening System.* PXP shall operate the skid-mounted gas sweetening system during all planned flaring events. PXP shall record in a log the amount of sulfa-check solution used per month and the date and volume of all sulfa-check shipments to the platform.

(v) *Purge Gas.* Sweetened produced gas or nitrogen may be used as the flare purge gas.

(vi) PXP shall comply with the revised *Platform Irene Flare Minimization Plan* approved by the District July 13, 1997 (and any revisions thereto) which includes the

"Planned-Continuous" Flaring Emissions Monitoring Program. This program is subject to termination if the District determines that exceedances of Rule 359 sulfur emission limits, as demonstrated by this program, result in excessive sulfur emissions.

(c) Monitoring: The following monitoring conditions apply to the flare relief system:

(i) *Flare Volumes.* The volumes of gas flared shall be monitored by use of the District-approved flare header flow meter. The meter shall be operated consistent with PXP's *Process Monitor Calibration and Maintenance Plan.*

(ii) *Purge and Pilot.* Sulfur content of purge and pilot gas by daily Draeger tube measurements. Propane used as pilot fuel gas that meets the Gas Processors Association standards does not need to be monitored by Draeger tube. Nitrogen purge gas does not need to be monitored by Draeger tube.

(iii) *Purge and Pilot Volumes.* The volumes of pilot gas, sweetened produced gas used as purge gas, and nitrogen used as purge gas.

(iv) *Flare Volume H_2S.* The H_2S concentration of planned flare volumes shall be monitored by the Del Mar analyzer consistent with the *CEMs Plan* and the *Flare Gas Sulfur Reporting Plan.*

(d) Recordkeeping: The following recordkeeping conditions apply to the flare relief system:

(i) *Flare Volumes.* All flaring events shall be recorded in a log. The log shall include: date; duration of flaring events (start and stop times); quantity of gas flared; reason for flaring events; the type of event (e.g., planned or unplanned) and a qualitative description of the gas flared including the sulfur content.

(ii) *Propane as Flare Fuel Gas.* PXP shall record in a log each usage of propane in a District-approved format and shall maintain documentation of the sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers.

(iii) *Purge and Pilot.* Purge (sweetened produced gas and nitrogen) and pilot gas volumes, and sulfur content of the propane and produced gas.

(iv) *Quarterly Visual Inspections*. The results of the quarterly one-minute visible emissions inspections required by permit condition 9.B.2.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report)* of Pt70 PTO 9106-R5. *[Ref: District Rules 359, 1303; ATC/PTO 12006; ATC/PTO 9612;ATC/PTO 13792; 40 CFR 70.6]*

C.3 **Fugitive Hydrocarbon Emissions Components.** The following equipment are included in this emissions unit category:

District Device No.	Name
5448	*Gas/Light Liquid Service Components*
5447	*Oil Service Components*

(a) Emission Limits: Mass emissions from the gas/light liquid service and oil service components listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rule 331.D and E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition PXP shall meet the following requirement:

(i) *I&M Program.* The District-approved I&M Plan for Platform Irene shall be implemented for the life of the project. The Plan, and any subsequent District approved revisions, is incorporated by reference as an enforceable part of this permit.

(ii) *Leak-Path Count.* The total leak-path component count listed in PXP's most recent I&M component leak-path inventory shall not exceed the total component and leakpath count line-item subtotals listed in Table 5.1-1 by more than five percent. This five percent range is to allow for minor differences due to component counting methods and does not constitute allowable emissions growth due to the addition of new equipment.

(iii) *Venting.* All routine venting of hydrocarbons shall be routed to either the sales compressor, flare header, injection well or other District-approved control device.

(iv) *BACT.* The component-leakpaths in hydrocarbon service listed in Table 4.2 are subject to BACT requirements pursuant to Rule 331. BACT, as defined in Table 4.2, shall be implemented for the life of the project.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in District Rule 331.F. The test methods in Rule 331.H shall be used, when applicable.

(d) Recordkeeping: All inspection and repair records shall be retained at the source for a minimum of five years. The equipment listed in this section are subject to all the recordkeeping requirements listed in District Rule 331.G. In addition, PXP shall:

(i) *I&M Log* - record in a log the following: a record of leaking components found (including name, location, type of component, date of leak detection, the ppmv reading, date of repair attempt, method of detection, date of re-inspection and ppmv reading after leak is repaired); a record of the total components inspected and the total number and percentage found leaking by component type; a record of leaks from critical components; a record of leaks from components that incur five repair actions within a continuous 12-month period; and, a record of component repair actions including dates of component re-inspections.

For the purpose of the above paragraph, a leaking component is any component which exceeds the applicable limit (e.g., greater than or equal to 1,000 ppmv for minor leaks under Rule 331; greater than or equal to 100 ppmv for E100 components)

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in District Rule 331.G. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report*). *[Re: District Rules 331 and 1303, PTO 9612; 40 CFR 70.6]*

C.4 **Crew and Supply Boats.** The following equipment is included in this emissions category:

Equip. No.	
Supply Boat (Santa Cruz)	
5449	Supply Boat Main Engines – Controlled
5451	Supply Boat – Bow Thruster
5450	Supply Boat – Auxiliary Engines
Support Vessels	
5452	Emergency Response (Clean Seas) Main/Aux Engines
101868	MOB

(a) Emission Limits: Mass emissions from the supply boats and support vessels servicing Platform Irene shall not exceed the limits in Tables 5.1-3 and 5.1-4. For purposes of enforcement, the emission limits of the bow thruster and auxiliary generators are combined (based on the total combined fuel use as required below in 9.C.4(b)(ii). In addition:

(i) NO_X Emissions - Controlled emissions of NO_x from each diesel fired main engine in the controlled supply boat listed in the above table shall not exceed 270 lb/1000 gallons (5.99 g/bhp-hr). In addition, spot charter supply boats, emergency response (e.g. Clean Seas) and the MOB and escape vessels shall not be required to comply with this controlled NO_x emission rate. Compliance shall be based on annual source testing consistent with the requirements listed in Table 4.1 and the source testing condition of this permit.

(b) Operational Limits - General: Operation of the equipment listed in this section shall not exceed the limits listed below. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit.

(i) *Supply Boat Main Engine Limits.* The combined fuel use for all the supply boats servicing Platform Irene shall not use more than: 1,401 gallons per day; 35,035 gallons per quarter; 140,140 gallons per year of diesel fuel.

(ii) *Supply Boat Auxiliary Engine Limits.* The supply boat auxiliary engines (generators and bow thruster) for the supply boats serving Platform Irene shall not use a combined total fuel use exceeding: 206 gallons per day; 5,122 gallons per quarter; 20,487 gallons per year of diesel fuel.

(iii) *Emergency Response Boat Engines.* The emergency response boat shall not use more than: 20,000 gallons per quarter; 80,000 gallons per year of diesel fuel. PXP's allocation of allowable emergency response boat fuel usage shall not exceed 5,000 gallons per quarter or 20,000 gallons per year of diesel fuel.

(iv) *Spot Charter Limits.* The number of allowable annual spot charter supply boat trips shall not exceed ten percent of the actual annual number of trips made by the controlled (i.e., primary) supply boats. Compliance shall be based on a comparison of the main engine fuel use for controlled and uncontrolled boats (i.e., the total main engine uncontrolled supply boat fuel use must be less than 10 percent of the total main engine controlled supply boat fuel use and the total main engine uncontrolled crew boat fuel use must be less than 10 percent of the total main engine controlled crew boat fuel use).

(v) *MOB.* The MOB and escape capsules shall be limited to 200 hours of operation per year.

(vi) *Liquid Fuel Sulfur Limit.* Diesel fuel used by all IC engines shall have a sulfur content no greater than 0.20 weight percent.

(vii) *New/Replacement Boats.* PXP may utilize any new/replacement project boat without the need for a permit revision if that boat meets the following conditions:

(a) The main engines are of the same or less bhp rating; and

(b) The combined pounds per day potential to emit (PTE) of all generator and bow thruster engines is the same or less than the sum of the pounds per day PTE for these engines as determined from the corresponding Table 5.1-3 emission line items of this permit; and

(c) The NO_x, ROC, CO, PM and PM_{10} emission factors are the same or less for the main and auxiliary engines. For the main engines, NO_x emissions must meet the 270 lb/1000 gallons emission standard.

The above criteria also apply to spot charter boats, except for the NO_x emission standard noted in (c) above. Any proposed new/replacement crew, supply or spot charter boat that does not meet the above requirements (a) - (c) shall first obtain a permit revision prior to operating the boat. The District may require manufacturer guarantees and emission source tests to verify this NO_X emission standard.

PXP shall revise the *Boat Monitoring and Reporting Plan*, obtain District approval of such revisions and implement the revised Plan prior to bringing any new/replacement boat into service, except for the use of spot charters. If a new spot charter is brought into service then PXP shall revise and resubmit the boat plan within thirty (30) calendar days after it is first brought into service. If the fuel metering and emissions computation procedures for a new spot charter are identical to a boat that is already addressed in the approved boat plan, a letter addendum stating this will suffice for the revision/re-submittal of the boat plan.

Prior to bringing the boat into service for the first time, PXP shall submit the information listed below to the District for any new/replacement crew and supply boat that meets the requirements set forth in (a) - (c) above, and for new spot charters that have not been previously used on the Point Pedernales Project. For spot charters, this information shall be submitted within thirty (30) calendar days after the boat is first brought into service. PXP shall notify the District Project Manager (via fax or e-mail) within three (3) calendar days after a new spot charter is first brought into operation. Any boat put into service that does not meet the requirements above, as determined by the District at any time, shall immediately cease operations and all prior use of that boat shall be considered a violation of this permit.

(d) Boat description, including the type, size, name, engine descriptions and emission control equipment.

(e) Engine manufacturers' data on the emission levels for the various engines and applicable engine specification curves.

(f) A quantitative analysis using the operating and emission factor assumptions given in tables 5.1-1 and 5.1-2 of this permit that demonstrates criteria (b) above is met.

(g) Estimated fuel usage within 25-miles of the Platform Irene

(h) Any other information the District deems necessary to ensure the new boat will operate consistent with the analyses that form the basis for this permit.

(c) Monitoring: The following monitoring requirements shall apply:

Boat Monitoring and Reporting Plan. PXP shall comply with the requirements of the District-approved *Boat Monitoring and Reporting Plan* (approved July 2006), and any subsequent updates, for documenting and reporting boat activity, fuel usage and emissions associated with the platform. PXP shall fully implement this Plan for the life of the project. This plan is hereby incorporated by reference as part of this permit.

The data from the Boat Plan shall demonstrate that the boats are being operated consistent with the emission assumptions used in the issuance of this operating permit. Fuel use for all the engines must be collected to determine emissions while the boat is in transit during a project related trip. Spot charter boats shall, at a minimum, track total fuel usage on a per trip basis using District-approved procedures. Emergency response boats shall, at a minimum, track fuel usage on a quarterly basis using District-approved procedures. Fuel use shall be tracked on a quarterly basis using District-approved procedures for emergency response boats. Hours of operation shall be monitored and recorded for the MOB and escape capsules. These data shall be submitted in a District-approved format to the District.

(d) Recordkeeping: The following records shall be maintained in legible logs and shall be made available to the District upon request:

(i) *Maintenance Logs.* For all main and auxiliary engines on controlled supply boats, maintenance log summaries that include details on injector type and timing, setting adjustments, major engine overhauls, and routine engine maintenance. These log summaries shall be made available to the District upon request. For each main and auxiliary engine with timing retard, a District Form -10 (IC Engine Timing Certification Form) must be completed each time the engine is serviced.

(ii) *Supply Boat Fuel Usage.* Daily, monthly, quarterly and annual fuel use for the supply boat main engines, auxiliary and bow thruster engines itemized by controlled and uncontrolled boats, i.e., separate fuel usage logs for the Santa Cruz.

(iii) *Emergency Response Boat Fuel Usage.* Total quarterly and annual fuel use for the emergency response boat and Platform Irene's allocation of that total.

(iv) *MOB/Escape Capsules Operational Hours.* The annual (calendar) hours of operation of the MOB and escape capsules.

(v) *Emissions Reporting.* Quarterly emissions from the supply and emergency boats shall be reported based on reported fuel use. Quarterly emissions from the MOB vessel shall be reported and based on the reported hours of use.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report).*
[Re: District Rule 1303;PTO 9106-06, ATC/PTO 11435, 40 CFR 70.6]

C.5 **Pigging Equipment.** The following equipment are included in this emissions category:

District Device No.	Name
101902	Oil Emulsion Pig Launcher
101903	Gas Pig Launch

(a) Emission Limits: Mass emissions from the gas and oil pig launchers and receivers listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rule 325.E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition PXP shall meet the following requirement:

(i) *Events.* The number oil and gas pig operations (events) shall not exceed the maximum operating schedule listed in Table 5.1-1.

(ii) *Openings.* Access openings to the pig launchers/receivers shall be kept closed at all times, except when a pipeline pig is being placed into or removed from the launcher/receiver.

(iii) *Pressure.* Prior to opening each gas or oil pig, the pressure in the pig shall not exceed 5 psig.

(c) Monitoring. none.

(d) Recordkeeping. PXP shall record in a log each pigging operation. The log shall include the date and pigging unit used (e.g., oil or gas).

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report*).
[Re: District Rules 325 and 1303, PTO 9106, 40 CFR 70.6]

C.6 **Sumps/Tanks/Separators.** The following equipment are included in this emissions category:

District Device No.	Name
5456	Waste Water Tank 530
5457	Waste Water Tank 540
5453	Sub-deck Sump A
5454	Sub-deck Sump B
5455	Sub-deck Sump C

(a) Emission Limits: Mass emissions from the equipment listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(b) Operational Limits: T-530 and T-540 shall meet the requirements of District Rule 325, Sections D.2, D.4, E, F, G and H. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit.

(i) Tanks T-530 and T-540 shall be equipped with solid roof covers. The pump suction set points on the pumps servicing sumps A, B and C shall be maintained between 1.0 and 1.5 inches from the bottom of each sump.

(ii) Sump A shall be visually inspected every two hours and drained by the sump pump, if necessary, to reduce the liquid level to the lowest possible level.

(iii) Sumps A and C shall be flushed and drained weekly with sea water.

(iv) Sump B shall be flushed daily with sea water in conjunction with the Omni-Pure unit, i.e., the sea water used to flush the Omni-Pure unit shall be discharged to Sump B. Sump B will then be flushed with this water and drained to the lowest possible level.

(c) Monitoring: Tanks 530 and 540 are subject to all the monitoring requirements of District Rule 325.H. The test methods outlined in District Rule 325.G shall be used, when applicable. In addition, PXP shall:

(i) analyze the process streams listed below:

- Produced Oil: Sample taken at outlet from production separator. Analysis for: API gravity; true vapor pressure (per Rule 325 methods). Samples shall be taken on a biennial basis.
- Purge and Pilot: Sample taken at flare header. Analysis for: HHV, total sulfur, hydrogen sulfide, composition.

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in District Rule 325.F. In addition, PXP shall maintain logs for the information listed below. These logs shall be made available to the District upon request:

(i) On a monthly basis, the total oil emulsion and produced gas production along with the number of days per month of production.

(ii) Process stream analyses data as required in permit condition 9.C.6(c) above.

(iii) Visual inspections of Sump A and whether pumping of liquid from the sump was required.

(iv) Weekly flushing of Sumps A and C and the daily flushing of Sump B.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report).*
[Ref: District Rules 325 and 1303, PTO 9106, 40 CFR 70.6]

C.7 **Solvent Usage.** The following equipment are included in this emissions unit category:

District Device No.	Name
101957	Cleaning/Degreasing

(a) Emission Limits: Mass emissions from the solvent usage shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(b) Operational Limits: Use of solvents for cleaning/degreasing shall conform to the requirements of District Rules 317, 322, 323 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and facility inspections.

(i) *Containers.* Vessels or containers used for storing materials containing organic solvents shall be kept closed unless adding to or removing material from the vessel or container.

(ii) *Materials*. All materials that have been soaked with cleanup solvents shall be stored, when not in use, in closed containers that are equipped with tight seals.

(iii) *Solvent Leaks*. Solvent leaks shall be minimized to the maximum extent feasible or the solvent shall be removed to a sealed container and the equipment taken out of service until repaired. A solvent leak is defined as either the flow of three liquid drops per minute or a discernible continuous flow of solvent.

(iv) *Reclamation Plan*. PXP shall comply with the Solvent Reclamation Plan approved by the District on June 6, 1997 (and any subsequent revisions) for the disposal of reclaimed solvent. As stated in this plan, all solvent disposed of pursuant to the Plan will not be assumed to have evaporated as emissions into the air and, therefore, will not be counted as emissions from the source.

(c) Monitoring: none.

(d) Recordkeeping: PXP shall record in a log the following on a monthly basis for each solvent used: amount used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed for District-approved disposal; whether the solvent is photochemically reactive; and, the resulting emissions to the atmosphere in units of pounds per month and pounds per day. Product sheets (MSDS or equivalent) detailing the constituents of all solvents shall be maintained in a readily accessible location on the platform.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.18 (*Semi-Annual Compliance Verification Report). [Ref: District Rules 317, 322, 323, 324; PTO 9106 PC 29, 40 CFR 70.6]*

C.8 **Facility Throughput Limitations.** Platform Irene production shall be limited to a monthly average of 150,000 barrels of oil emulsion per day, 36,000 barrels of dry oil per day and 12 million standard cubic feet of produced gas per day. PXP shall record in a log the volumes of oil emulsion and gas produced and the actual number of days in production per month. The above limits are based on actual days of operation during the month.
[Ref: PTO 9106 PC 16]

C.9 **Produced Gas.** PXP shall direct all produced gases to the sales compressors, the flare header or other permitted control device when de-gassing, purging or blowing down any oil and gas well or tank, vessel or container that contains reactive organic compounds or reduced sulfur compounds due to activities that include, but are not limited to, process or equipment turnarounds, process upsets (e.g., well spikes), well blow down and BOEM ordered safety tests. *[Ref: District Rules 325, 331, PTO 9106 PC 17]*

C.10 **Diesel IC Engines - Particulate Matter Emissions.** To ensure compliance with District Rules 205.A, 302, 304, 309 and the California Health and Safety Code Section 41701, PXP shall implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. PXP shall comply with the District-approved *IC Engine Particulate Matter Operation and Maintenance Plan* (January 4, 2000) and all District-approved updates thereof) for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules that PXP will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized. All project diesel-fired engines, regardless of exemption status, shall be included in this Plan. *[Ref: District Rules 205.A, 302, 304, 309, PTO 9106 PC 22]*

C.11 **Abrasive Blasting Equipment.** All abrasive blasting activities performed on Platform Irene shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530. *[Ref: PTO 9106 PC 24]*

C.12 **Process Monitoring Systems - Operation and Maintenance.** All platform process monitoring devices listed in Section 4.11.2 of this permit shall be properly operated and maintained according to manufacturer recommended specifications. PXP shall comply with the District-approved *Process Monitor Calibration and Maintenance Plan* (revised May 11 2009), and all subsequent District-approved updates, for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment is utilized. *[Re: PTO 9106 PC 25]*

C.13 **Source Testing.** The following source testing provisions shall apply:

(i) PXP shall conduct source testing of air emissions and process parameters listed in Table 4.1 of this permit. More frequent source testing may be required if the equipment does not comply with permitted limitations or if other compliance problems, as determined by the APCO, occur. Source testing of the crane engines shall be performed on a biennial schedule (August anniversary date). The crane engine shall be loaded to the maximum safe load obtainable. Source testing of the supply boat shall occur on an annual basis (September anniversary date). The supply boat main engines shall be tested at normal cruise speeds as approved in the source test plan.

(ii) PXP shall submit a written source test plan to the District for approval at least thirty (30) calendar days prior to initiation of each source test. The source test plan shall be prepared consistent with the District's *Source Test Procedures Manual* (revised May 1990 and any subsequent revisions). PXP shall obtain written District approval of the source test plan prior to commencement of source testing. The District shall be notified at least ten (10) calendar days prior to the start of source testing activity to arrange for a mutually agreeable source test date when District personnel may observe the test.

(iii) A source test for an item of equipment shall be performed on the scheduled day of testing (the test day mutually agreed to) unless circumstances beyond the control of the operator prevent completion of the test on the scheduled day. Such circumstances include mechanical malfunction of the equipment to be tested, malfunction of the source test equipment, delays in source test contractor arrival and/or set-up, or unsafe conditions on site. Except in cases of an emergency, the operator shall seek and obtain District approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. If the test cannot be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the District. Failing to perform the source test of an equipment item on the scheduled test day without a valid reason and without District's prior authorization, except in the case of an emergency, shall constitute a violation of this permit. If a test is postponed due to an emergency, written documentation of the emergency event shall be submitted to the District by the close of the business day following the scheduled test day.

Source test results shall be submitted to the District within forty-five (45) calendar days following the date of source test completion and shall be consistent with the requirements approved within the source test plan. Source test results shall demonstrate compliance with emission rates in Section 5 and applicable permit conditions. All District costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by PXP as provided for by District Rule 210.

The timelines in i, ii, and iii above may be extended for good cause provided a written request is submitted to the District at least three (3) days in advance of the deadline, and approval for the extension is granted by the District. *[Ref: PTO 9106]*

C.14 **Offsets - Platform Irene FWKO/VRU Compressor Project.** PXP shall offset all reactive organic compound (ROC) emissions pursuant to Table 7.0 Emission reduction credits (ERCs) sufficient to offset the permitted quarterly ROC emissions shall be in place for the life of the project.

C.15 **Maximum H_2S Concentrations.** The maximum H_2S concentration of the gas in the Surf to Shoreline segment of the gas transmission line from Platform Irene to the LOGP, as measured by colorimetric tube, or District equivalent, shall not exceed 8,000 ppmv. PXP shall sample daily for H_2S and maintain a log of the daily ppmv results. Any measured value greater than 8,000 ppmv shall constitute a violation of this permit. Measurements of the pipeline H_2S concentration shall comply with the following procedures:

(1) The lower range of the colorimetric tubes used for daily measurements shall be no less than 1000 ppm and the upper range no greater than 10,000 ppm, or other range as approved by the District.

(2) If any daily colorimetric tube measurement exceeds 6,000 ppmv the District may require sampling at increased frequency or third-party sampling/analysis. PXP shall report any concentrations above 6000 ppmv to the District the next business day. PXP shall implement any additional required sampling within 24 hours, or other District approved time period, of written notification by the District. In addition, PXP shall reinstate continuous monitoring of the pipeline H_2S concentration if the District determines based on data trends that there is potential for violations of the 8000 ppmv limit. Installation and operation of continuous monitoring equipment shall occur within 90 days of District written notification, or other District approved time, *[Ref: PTO 9106-08]*

C.16 **Process Stream Sampling and Analysis.** PXP shall sample analyze the process streams listed in Section 4.11 of this permit according to the methods and frequency detailed in that Section. All process stream samples shall be taken according to District approved ASTM methods and must follow traceable chain of custody procedures. *[Ref: PTO 9106 PC 27]*

C.17 **Recordkeeping.** All records and logs required by this permit and any applicable District, state or federal rule or regulation shall be maintained for a minimum of five calendar years from the date of information collection and log entry at the platform. These records or logs shall be readily accessible and be made available to the District upon request.
[Re: District Rule 1303, PTO 9106 PC 27; 40 CFR 70.6]

C.18 **Semi-Annual Compliance Verification Reports.** Twice a year, PXP shall submit a compliance verification report to the District. Each report shall be used to verify compliance with the prior two calendar quarters. The first report shall cover calendar quarters 1 and 2 (January through June) and shall be submitted no later than September 1. The second report shall cover calendar quarters 3 and 4 (July through December) and shall be submitted no later than March 1. Each report shall contain information necessary to verify compliance with the emission limits and other requirements of this permit (if applicable for that quarter). These reports shall be in a format approved by the District. All logs and other basic source data not included in the report shall be available to the District upon request. The second report shall also include an annual report for the prior four quarters. Pursuant to Rule 212, the annual report shall include a completed *District Annual Emissions Inventory* questionnaire. The report shall include the following information:

(a) *Internal Combustion Engines.*

(1) The daily, quarterly and annual hours of operation for each pedestal crane and air compressor engines.

(2) The monthly and cumulative annual hours of operation for the fire water pump, drill rig emergency power generators, production emergency power generator (by ID number) and emergency water pump.

(3) Results of the quarterly Rule 333 portable NO_x analyzer readings.

(4) Total sulfur content of each diesel fuel shipment. Biennially, the higher heating value of the diesel fuel (Btu/gal).

(5) Summary results of all compliance emission source testing performed.

(6) The results of all Method 9 quarterly VEE inspections required by permit Condition 9.B.2.

(7) records of maintenance conducted pursuant to Subpart ZZZZ.

(b) *Flare*.

(1) The volumes of gas combusted and resultant mass emissions for each flare category (i.e., Purge/Pilot; Planned Continuous; Planned Other and Unplanned) and the reason for the flare event.

(2) The H_2S concentration of all flare events.

(3) The daily volume and total sulfur content of flare purge and pilot fuel gas.

(4) Highest daily H_2S concentration (for each week) of the continuous flare gas stream as reported by the Del Mar H_2S analyzer.

(5) The results of all Method 9 VEE inspections required by permit condition 9.B.2.

(c) *Fugitive Hydrocarbons*. Rule 331/Enhanced Monitoring fugitive hydrocarbon I&M program data (on a quarterly basis):

(1) Inspection summary.

(2) Record of leaking components.

(3) Record of leaks from critical components.

(4) Record of leaks from components that incur five repair actions within a continuous 12-month period.

(5) Record of component repair actions including dates of component re-inspections.

(6) An updated FHC I&M inventory due to change in component list or diagrams.

(7) Listing of components installed as BACT under District Rule 331 as approved by the District.

(d) *Supply Boats*.

(1) Daily, quarterly and annual fuel use for the supply boat main engines and auxiliary engines (including the bow thruster engine), itemized by controlled boat usage and uncontrolled boat usage.

(2) The sulfur content of each delivery of diesel fuel used by the supply boat.

(3) Information regarding any new project boats servicing Platform Irene as detailed in Permit Condition 9.C.4(e) above.

(4) Maintenance log summaries including details on injector type and timing, setting adjustments, major engine overhauls, and routine engine tune-ups. For spot charters this shall be provided as available.

(5) Summary results of all compliance emission source testing performed.

(6) *MOB/Escape Capsules Operational Hours*. The annual (calendar) hours of operation of the MOB and escape capsules.

(7) *Emissions Reporting* - Quarterly emissions from the supply and emergency boats shall be reported based on reported fuel use. Quarterly emissions from the MOB vessel shall be reported and based on the reported hours of use

(e) *Pigging*. For each pig receiver and launcher, the number of pigging events per day, quarter and year.

(f) *Tanks/Sumps/Separators*.

(1) On a monthly basis, the total oil emulsion and produced gas production along with the number of days per month of production.

(2) Process stream analyses data specified in permit Condition 9.C.16.

(3) Visual inspections of Sump A and whether pumping of liquid from the sump was required.

(4) Weekly flushing of Sumps A and C and the daily flushing of Sump B.

(g) *Solvent Usage*. On a monthly basis: the amount of solvent used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed; whether the solvent is photochemically reactive; and, the resulting emissions of ROC and photochemically reactive solvents to the atmosphere in units of pounds per month.

(h) *General Reporting Requirements*.

(1) On a quarterly basis, the emissions from each permitted emission unit for each criteria pollutant.

(2) On a quarterly basis, the emissions from each exempt emission unit for each criteria pollutant.

(3) On a quarterly basis, shall submit data for CEM downtime and CEM detected excess emissions in a format approved by the District.

(4) A summary of each and every occurrence of non-compliance with the provisions of this permit, District rules, and any other applicable air quality requirement.

(5) The produced gas, produced oil, fuel gas, and produced wastewater process stream analyses as required by condition 9.C.16 of this permit. Process stream analyses per Section 4.11.

(6) Breakdowns and variances reported/obtained per Regulation V along with the excess emissions that accompanied each occurrence.

(7) Helicopter trips (by type and trip segments with emission calculations).

(8) On an annual basis, the ROC and NO_x emissions from all permit exempt activities.

(9) Tons per quarter totals of all pollutants (by each emission unit). The third/fourth quarter report shall include tons per year totals for all pollutants (by each emission unit).

(10) A copy of all completed District-10 forms (*IC Engine Timing Certification Form*).

(11) A copy of the Rule 202 De Minimis Log for the stationary source.

(12) Results of daily calorimetric measurements of the H_2S content of the produced gas which exceed 6,000 ppmv as required by permit condition 9.C.15.

C.19 **Emergency Episode Plan.** During emergency episodes, PXP shall implement the Emergency Episode Plan approved District on December 12, 2000.
[Re: District Rule 1303, PTO 9106]

C.20 **Mass Emission Limitations.** Mass emissions for each equipment item (i.e., emissions unit) associated with Platform Irene shall not exceed the values listed in Tables 5.1-3 and 5.1-4. Emissions for the entire facility shall not exceed the total limits listed in Table 5.2.

[*Re: District Rule 1303, PTO 9106*]

C.21 **Standby/Emergency Diesel IC Engines.** The following equipment are included in this emissions unit category:

Device ID #	Device Name
005460	IC Engine: Emergency Generator, Drilling
005461	IC Engine: Emergency Generator, Drilling
005084	IC Engine: Emergency Generator, Production
005462	IC Engine: Fire Water Pump

(a) Emission Limits: The mass emissions from the equipment permitted herein shall not exceed the values listed in Table 5.1-3 and 5.1-4. Emissions of PM and other pollutants shall not exceed the emissions standards listed in Table 5.1-2 of this permit. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit. These limits are based on the maintenance and testing operational limits listed in permit condition C.21(b)(i) below.

(b) Operational Limits: The equipment permitted herein is subject to the following operational restrictions listed below. Emergency use operations, as defined in Section (d)(25) of the ATCM[6], have no operational hours limitations.

(i) *Maintenance & Testing Use Limit:* The stationary emergency standby diesel-fueled CI engine(s) subject to this permit, shall limit maintenance and testing[7] operations to no more than 2 hours per day and 200 hours per year.

(ii) *Fuel and Fuel Additive Requirements:* The permittee may only add CARB Diesel, or an alternative diesel fuel that meets the requirements of the ATCM Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the ATCM Verification Procedure, or any combination of the above to the engine or any fuel tank directly attached to the engine.

(iii) The drill rig emergency generator engines may be used only for the purpose of securing wells and allowing for the safe shutdown of platform operations. The drill rig engines may not be used to advance drilling or production operations. The Platform Irene water pump may be tested as needed for the weekly performance tests but shall not be tested while testing of the onshore pumps (960 and 970) is being conducted.

(iv) *Engine Maintenance - Emergency Drilling Generator (ID 5460), Emergency Drilling Generator (ID 5461), Emergency Production Generator (ID 5084) and Emergency Firewater Pump (ID 5462)* - Existing emergency standby compression

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[6] As used in the permit, "ATCM" means Section 93115, Title 17, California Code of Regulations. Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines

[7] "maintenance and testing" is defined in Section (d)(41) of the ATCM

ignition reciprocating internal combustion engines (RICE) must comply with the applicable operating limits by no later than May 3, 2013. The following operating requirements apply:

(1) Change the oil and filter every 500 hours of operation or annually, whichever comes first. In place of changing the oil every 500 hours of operation or annually, the operator may analyze the oil of each engine every 500 hours of operation or annually, whichever occurs first. The analysis shall measure the Total Base Number, the oil viscosity, and the percent water content. The oil and filter shall be changed if any of the following limits are exceeded:

(a) The tested Total Base Number is less than 30 percent of the Total Base Number of the oil when new.

(b) The tested oil viscosity has changed by more than 20 percent from the oil viscosity when new.

(c) The tested percent water content (by volume) is greater than 0.5 percent.
[*ref: 40 CFR §63.6625*]

(2) Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first.

(3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

(c) Monitoring**.** The equipment permitted herein is subject to the following monitoring requirements:

(i) *Non-Resettable Hour Meter:* Each stationary diesel-fueled CI engine(s) subject to this permit shall have installed a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District has determined (in writing) that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.

(d) Recordkeeping. The permittee shall record and maintain the information listed below. Log entries shall be retained for a minimum of 36 months from the date of entry. Log entries made within 24 months of the most recent entry shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to District staff within 5 working days from request. District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*) can be used for this requirement.

(i) Emergency use hours of operation;

(ii) Maintenance and testing hours of operation;

(iii) Hours of operation for all uses other than for emergency use and maintenance and testing, along with a description of what those hours were for.

(iv) Documentation of fuel use through the retention of fuel purchase records that account for all fuel purchased for use in the engines located on the OCS platform. PXP shall only purchase fuel that meets the CARB ATCM requirement and at a minimum, PXP shall maintain the following information for each fuel purchase transaction:

   (1) identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;

   (2) amount of fuel purchased;

   (3) date when the fuel was purchased;

   (4) signature of owner or operator or representative of owner or operator who received the fuel;

   (5) signature of fuel provider indicating fuel was delivered, or other documentation where the fuel was obtained.

(v) Results of the quarterly one-minute visible emissions inspections required by permit condition 9.B.2.

(vi) For each engine subject to Subpart ZZZZ the following records shall be kept:

   (1) The date of each engine oil change and the number of hours of operation since the last oil change.

   (2) The date and results of each oil analysis if the results of the oil analysis were used as the basis for not changing the oil every 500 hours or annually, whichever came first.

   (3) The date of each engine air filter inspection and the number of hours of operation since the last air filter inspection. Indicate if the air filter was replaced as a result of the inspection.

   (4) The date of each engine's hose and belts inspection and the number of hours of operation since the last hose and belt inspection. Indicate if any hose or belt was replaced as a result of the inspection.

(e) Temporary Engine Replacements - DICE ATCM**.** Any reciprocating internal combustion engine listed in permit condition C.21 and subject the stationary diesel ATCM may be replaced temporarily only if the requirements (i - iii) listed herein are satisfied.

(i) The permitted engine is in need of routine repair or maintenance.

(ii) The permitted engine that is undergoing routine repair or maintenance is returned to its original service within 180 days of installation of the temporary engine.

(iii) The temporary replacement engine has the same or lower manufacturer rated horsepower and same or lower potential to emit of each pollutant as the permitted engine that is being temporarily replaced. At the written request of the permittee, the District may approve a replacement engine with a larger rated horsepower than the permitted engine if the proposed temporary engine has manufacturer guaranteed emissions (for a brand new engine) or source test data (for a previously used engine) less than or equal to the permitted engine.

(iv) The temporary replacement engine shall comply with all rules and permit requirements that apply to the permitted engine that is undergoing routine repair or maintenance.

(v) For each permitted engine to be temporarily replaced, the permittee shall submit a completed *Temporary IC Engine Replacement Notification* form (Form ENF-94) within 14 days of the temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD Engineering Supervisor.

(vi) Within 14 days upon return of the original permitted engine to service, the permittee shall submit a completed *Temporary IC Engine Replacement Report* form (Form ENF-95). This form shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD Engineering Supervisor.

Any engine in temporary replacement service shall be immediately shut down if the District determines that the requirements of this condition have not been met. This condition does not apply to engines that have experienced a cracked block (unless under manufacturer's warranty), to engines for which replacement parts are no longer available, or new engine replacements {including "reconstructed" engines as defined in Section (d)(44) of the ATCM}. Such engines are subject to the provisions of New Source Review and the new engine requirements of the ATCM.

(f) Permanent Engine Replacements. Any E/S engine, firewater pump engine or engine used for an essential public service that breaks down and cannot be repaired may install a new replacement engine without first obtaining an ATC permit only if the requirements (i-v) listed herein are satisfied.

(i) The permitted stationary diesel IC engine is an E/S engine, a firewater pump engine or an engine used for an essential public service (as defined by the District).

(ii) The engine breaks down, cannot be repaired and needs to be replaced by a new engine.

(iii) The facility provides "good cause" (in writing) for the immediate need to install a permanent replacement engine prior to the time period before an ATC permit can be obtained for a new engine. The new engine must comply with the requirements of the ATCM for new engines. If a new engine is not immediately available, a temporary engine may be used while the new replacement engine is being procured. During this time period, the temporary replacement engine must meet the same guidelines and procedures as defined in the permit condition above (*Temporary Engine Replacements - DICE ATCM*).

(iv) An Authority to Construct application for the new permanent engine is submitted to the District within 15 days of the existing engine being replaced and the District permit for the new engine is obtained no later than 180 days from the date of engine replacement (these timelines include the use of a temporary engine).

(v) For each permitted engine to be permanently replaced pursuant to the condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of either the permanent or temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD Engineering Supervisor.

Any engine installed (either temporally or permanently) pursuant to this permit condition shall be immediately shut down if the District determines that the requirements of this condition have not been met.

(g) Notification of Non-Compliance. Owners or operators who have determined that they are operating their stationary diesel-fueled engine(s) in violation of the requirements specified in Sections (e)(1) of the ATCM shall notify the District immediately upon detection of the violation and shall be subject to District enforcement action.

(h) Notification of Loss of Exemption. Owners or operators of in-use stationary diesel-fueled CI engines, who are subject to an exemption specified in Section (c) from all or part of the requirements of Section (e)(2), shall notify the District immediately after they become aware that the exemption no longer applies and pursuant to Section (e)(4)(F)(1) of the ATCM shall demonstrate compliance within 180 days after notifying the District.

9.D District-Only Conditions

D.1 **Nuisance (Rule 303).** No pollutant emissions from any source at PXP shall create nuisance conditions. No operations shall endanger health, safety or comfort, nor shall they damage any property or business. *[Ref: District Rule 303]*

D.2 **External Combustion Units - Permits Required.**

(a) An ATC/PTO permit shall be obtained prior to installation of any grouping of Rule 360 applicable boilers or hot water heaters whose combined system design heat input rating exceeds 2.000 MMBtu/hr.

(b) An ATC permit shall be obtained prior to installation, replacement, or modification of any existing Rule 361 applicable boiler or water heater rated over 2.000 MMBtu/hr.

(c) An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane except as provided for by District Rule 202.L.15 and L.16.

D.10 **Documents Incorporated by Reference:** The documents listed below, including any District-approved updates thereof, are incorporated herein and shall have the full force and effect of a permit condition for this operating permit. These documents shall be implemented for the life of the Project and shall be made available to District inspection staff upon request.

Fugitive Emissions Inspection and Maintenance Plan

Internal Combustion Engines Maintenance Plan

Flare Minimization Plan for Platform Irene revised on July 14, 1997

Emergency Episode Plan updated December 2000

Flare Sulfur Monitoring Plan

Boat Monitoring and Reporting Plan (July 2006)

Platform Irene Process Monitor Calibration and Maintenance Plan (revised May 11, 2009)

Flare Gas Sulfur Reporting Plan

AIR POLLUTION CONTROL OFFICER

____

____

Date

NOTES:

(a) Permit Reevaluation Due Date: December 2015
(b) Part 70 Operating Permit Expiration Date: December 2015

(c) This permit supersedes all previously issued permits for this facility.

10.0 Attachments

10.1 Emission Calculation Documentation

10.2 Permit Renewal Fee

10.3 Equipment List

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10.1 EMISSION CALCULATION DOCUMENTATION

PLATFORM IRENE

This attachment contains all relevant emission calculation documentation used for the emission tables in Section 5. Refer to Section 4 for the general equations used. The letters A-H refer to Tables 5.1-1 and 5.1-2.

Reference A - Combustion Engines

- The maximum operating schedule is in units of hours

- The default diesel fuel #2 characteristics are:
  - density = 7.043 lb/gal (36^{O} API)
  - LHV = 18,410 Btu/lb (129,700 Btu/gal)
  - HHV = 19,620 Btu/lb (138,200 Btu/gal)

- BSFC = 7,143 Btu/bhp-hr (North crane engine)
  - energy based value using LHV
  - B-60 injector, 210 bhp at 2100 rpm
  - Detroit Diesel 6L-71N engine specification basis = 0.388 lb/bhp-hr

- BSFC = 7,069 Btu/bhp-hr (South crane engine)
  - energy based value using LHV
  - B-55 injector, 197 bhp at 2100 rpm
  - Detroit Diesel 6L-71N engine specification basis = 0.384 lb/bhp-hr

- Emission factors units (lb/MMBtu) are based on HHV.

- LCF (LHV to HHV) value of 6 percent used.

- NO_x emission factor for North crane engine based on Rule 333 limit (8.4 g/bhp-hr)
  - $E_{lb/MMBtu}$ = [(8.4 g/bhp) x (10^6)] / [(7143 Btu/bhp-hr) x (1.06) x (453.6)]

- NO_x emission factor for South crane engine based on Rule 333 limit (8.4 g/bhp-hr)
  - $E_{lb/MMBtu}$ = [(8.4 g/bhp) x (10^6)] / [(7069 Btu/bhp-hr) x (1.06) x (453.6)]

- ROC, CO and PM emission factors based on USEPA AP-42, Table 3.3-1 (7/93)

- SO_x emissions based on mass balance
  - SO_x (as SO_2) = (%S) x (ρ_{oil}) x (20,000) / (HHV)

- Allowable sulfur content of 0.20 wt. %

- PM_{10}:PM ratio = 0.96; ROC:TOC ratio = 1.0

- Crane engine operational limits: General Equation

Q = (BSFC) x (bhp) x (LCF) x (hours/time period) / (HHV, Btu/gal)

North crane engine

Q = (7143 Btu/bhp-hr) x (210 bhp) x (1.06) x (24 hrs/day)/(138,200 Btu/gal)
= 276 gallons per day

Q = (7143 Btu/bhp-hr) x (210 bhp) x (1.06) x (730 hrs/qtr)/(138,200 Btu/gal)
= 8,399 gallons per quarter

Q = (7143 Btu/bhp-hr) x (210 bhp) x (1.06) x (2920 hrs/yr)/(138,200 Btu/gal)
= 33,595 gallons per year

South crane engine

Q = (7069 Btu/bhp-hr) x (197 bhp) x (1.06) x (24 hrs/day)/(138,200 Btu/gal)
= 256 gallons per day

Q = (7069 Btu/bhp-hr) x (197 bhp) x (1.06) x (730 hrs/qtr)/(138,200) Btu/gal)
= 7,797 gallons per quarter

Q = (7069 Btu/bhp-hr) x (197 bhp) x (1.06) x (2920 hrs/yr)/(138,200 Btu/gal)
= 31,189 gallons per year

Reference B - Combustion Flare

- The maximum operating schedule for the purge/pilot gas and planned continuous flaring is in units of hours

- The maximum operating schedule for the planned other and unplanned flaring is in units of percentage of annual usage

- Pilot Flow Rate: 55 scfh (0.482 MMscf/yr). Purge Rate: 55scfh of Nitrogen (0.482 MMscf/yr.)

- HHV = 1,318 Btu/scf for all flare gas (per PXP applcn)

- Planned continuous flaring value based on one half the minimum detection limit of the flare meter.

  Flare meter: Fluid Components LT 81 mass flow detection
  Minimum flow detection limit of flow element: 0.25 standard ft per second
  Flare header diameter: 12-inches (i.e., area = 0.785 ft^3)
  Minimum detection limit: 0.017 mmscfd (707 scfh)

- SO_x emissions from "planned continuous flaring": purge and pilot emissions (45 scfh) based on Rule 359 limit of (796 ppmvd S); SO_x emissions from the remainder of "planned continuous flaring" (358 scfh) based on 796 ppmvd S.

- Planned intermittent (other) and unplanned flaring volumes based on PXP appcln

- All planned intermittent (other) flaring gas meets Rule 359 sulfur limit of 796 ppmv through the use of a skid mounted sulfur control device

- Planned intermittent (other) and unplanned flaring events not calculated for short-term events per District policy

- The same emission factors are used for all flaring scenarios

- NO_x, ROC and CO emission factors based on USEPA AP-42, Table 11.5-1 (9/91)

- PM emission factor based on District Flare Study - Phase I Report, Table 3.1.1 (7/91)

- ROC:TOC ratio = 0.86; PM_{10}:PM ratio = 1.0

- SO_x emissions based on mass balance
  SO_x (as SO_2) = (0.169) x (ppmv S) / (HHV)

Reference C - Fugitive Components

- The maximum operating schedule is in units of hours

- All safe to monitor components are credited an 80 percent control efficiency. Unsafe to monitor components (as defined in Rule 331) are considered uncontrolled.

- The component leak path definition differs from the Rule 331 definition of a component. A typical leak path count for a valve would be equal to 4 (one valve stem, a bonnet connection and two flanges).

- Leak path counts are provided by applicant. The total count has been verified to be accurate within 5 percent of the District's P&ID and platform review/site checks.

- Emission factors based on District Policy and Procedure 6100.061.1996.

Reference D - Supply Boat

- The maximum operating schedule is in units of hours.

- Supply boat engine data based on Rincon Marine's *M/V Santa Cruz*.

- Two 2,000 bhp main engines (i.e., 4,000 bhp), two 245 bhp auxiliary engines (i.e., 490 bhp) and one 515 bow thruster engine are utilized.

- Main engine load factor based on District *Crew and Supply Boat* study (6/87).

- Supply boat bow thruster engine only operates during maneuver mode.

- Supply boat generator engines provide half of total rated load, either with one engine at full load or both engines at half load.

- Total time supply boat operates per trip within 25 miles of platform is 11 hours. A trip includes time traveling to and from the platform, as well as time operating at the platform. Typical trip is: 8 hours cruise, 2 hours maneuver and 1 hour idle. Annual time based on 100 trips. Quarterly based on 25 trips. Spot charter boats adds 110 hours to the PTE.

- Main engine emission factors are based only on cruise mode values.

- The brake specific fuel consumption (BSFC) for the controlled main engines is 0.345 lb/bhp-hr. This value is from data supplied by Caterpillar for operation of each engine at 1,340 bhp. This bhp was used to select the BSFC because the engines are assumed to operate at 65% of full capacity during normal operations.

- The BSFC was converted from lb/hp-hr to gal/hp-hr by dividing the manufacturer's BSFC by 7.05 lb/gal, the density of diesel:

  0.049 gal/hp-hr = (0.345 lb/hp-hr) / (7.05 lbs/gal)

- Supply boat main engines achieve a controlled NO_x emission rate of 5.99 g/bhp-hr through the use of Caterpillar 3516B diesel fired engines. The engines are electronically controlled, turbo-charged, and after-cooled. This emission factor equates to 270 lb/1000 gallons.

  EF_{NOx} = (5.99 g/bhp-hr) / (0.049 gal/bhp-hr) / (453.6 g/lb) X (1,000)

- Spot charter supply boat usage limited to 10 percent of actual annual controlled supply boat usage.

- Spot charter and Emergency Response vessels are normally uncontrolled for NO_x.

- Uncontrolled ROC and CO emission factors for the main engines are based on USEPA AP-42, Volume II, Table II-3.3 (1/75) {cruise factor, 2,000 bhp/engine}.

- Uncontrolled NO_x emissions from spot charter supply and emergency response boat main engines based on an emission rate of 14 g/bhp-hr. This emission factor equates to 561 lb/1000 gallons:

$$EF_{NOx} = (14 \text{ g/bhp-hr}) / (0.055 \text{ gal/bhp-hr}) / (453.6 \text{ g/lb}) \text{ X } (1{,}000)$$

- PM emission factor for the main engines are based on *Kelly, et. al.* (1981).

- PM_{10}:PM ratio = 1.00 (per AP-42); ROC:TOC ratio = 1.0

- All SO_x emissions based on mass balance:

$$SO_x \text{ (as } SO_2) = (\%S) (\rho_{oil}) (20{,}000) / (HHV)$$

- Auxiliary and bow thruster engine emission factors (uncontrolled) are based on USEPA AP-42, Table 3.3-1 (7/93). Table emission factors converted to fuel basis using:

$$EF_{lb/1000 \text{ gal}} = (EF_{lb/MMBtu}) (19{,}300 \text{ Btu/lb}) (7.05 \text{ lb/gal}) / (1000)$$

- Spot charter engine set-up assumed to be equal to main supply boat.

- Emergency response vessel is permanently assigned to Platforms Irene, Harvest, Hermosa, and Hidalgo. Short-term emissions from this vessel are not assessed. Long-term emissions are assessed equally amongst the four affected platforms.

- Emergency response vessel emissions calculated as an aggregate (main and auxiliary engines) using the uncontrolled supply boat emission factors. The long term hours of operating are back-calculated based on the fuel usage allocation for this platform of 20,000 gallons per year (80,000 gal/yr basis).

$$T_{yr} = (20{,}000 \text{ gal/yr}) / ((0.055 \text{ gal/bhp-hr}) (4{,}400 \text{ bhp}) (0.65)) = 127 \text{ hr/yr}$$

- Main and auxiliary engine operational limits: General Equation

$$Q = (BSFC) (bhp) (\text{hours/time period}) (\text{load factor})$$

Main engines

$$\begin{aligned} Q &= (0.049 \text{ gal/bhp-hr}) (4{,}000 \text{ bhp}) (11 \text{ hours/day}) (0.65) \\ &= 1{,}400 \text{ gallons per day} \\ Q &= (0.049 \text{ gal/bhp-hr}) (4{,}000 \text{ bhp}) (275 \text{ hours/qtr}) (0.65) \\ &= 35{,}035 \text{ gallons per quarter} \\ Q &= (0.049 \text{ gal/bhp-hr}) (4{,}000 \text{ bhp}) (1100 \text{ hours/yr}) (0.65) \\ &= 140{,}140 \text{ gallons per year} \end{aligned}$$

Auxiliary engines – Generators

$$\begin{aligned} Q &= (0.055 \text{ gal/bhp-hr}) (490 \text{ bhp}) (11 \text{ hours/day}) (0.50) \\ &= 148 \text{ gallons per day} \end{aligned}$$

Q = (0.055 gal/bhp-hr) (490 bhp) (275 hours/qtr) (0.50)
= 3,706 gallons per quarter
Q = (0.055 gal/bhp-hr) (490 bhp) (11004 hours/yr) (0.50)
= 14,822 gallons per year

Auxiliary engines - Bow Thruster

Q = (0.055 gal/bhp-hr) (515 bhp) (2 hours/day)
= 57 gallons per day
Q = (0.055 gal/bhp-hr) (515 bhp) (50 hours/qtr)
= 1,416 gallons per quarter
Q = (0.055 gal/bhp-hr) (515 bhp) (200 hours/yr)
= 5,665 gallons per year.

<u>Reference G - Sumps/Tanks/Separators</u>

- Maximum operating schedule is in units of hours

- Emission calculation methodology based on the CARB/KVB report *Emissions Characteristics of Crude Oil Production Operations in California* (1/83)

- Calculations are based on surface area of emissions unit as supplied by the applicant

- All emission units are classified as secondary production and heavy oil service

- Controls are not utilized on any emissions unit

<u>Reference H - Solvents</u>

- All solvents not used to thin surface coatings are included in this equipment category

- Daily, quarterly and annual emission rates per applcn

- Hourly emissions based on daily value divided by an average 8-hour day. Compliance with hourly data to be based on daily actual usage divided by 8.

<u>Reference I – Greenhouse Gas Calculations</u>

Combustion Sources:
GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO_2 equivalent emission factors are calculated for CO_2, CH_4, and N_2O individually, then summed to calculate a total CO_{2e} emission factor. Annual CO_{2e} emission totals are presented in short tons.

For IC engines, the emission factor in lb/MMBtu heat input is converted to g/bhp-hr output based on a standard brake-specific fuel consumption.

For natural gas combustion the emission factor is:

(53.02 kg CO_2/MMBtu) (2.2046 lb/kg) = 116.89 lb CO_2/MMBtu

(0.001 kg CH_4/MMBtu) (2.2046 lb/kg)(21 lb CO_2e/lb CH4) = 0.046 lb CO_2e/MMBtu

(0.0001 kg N_2O/MMBtu) (2.2046 lb/kg)(310 lb CO_2e/lb N_2O) = 0.068 lb CO_2e/MMBtu

Total CO2e/MMBtu = 116.89 + 0.046 + 0.068 = <u>117.00 lb CO_2e/MMBtu</u>

For diesel fuel combustion the emission factor is:

(73.96 kg CO_2/MMBtu) (2.2046 lb/kg) = 163.05 lb CO_2/MMBtu

(0.003 kg CH_4/MMBtu) (2.2046 lb/kg)(21 lb CO_2e/lb CH4) = 0.139 lb CO_2e/MMBtu

(0.0006 kg N_2O/MMBtu) (2.2046 lb/kg)(310 lb CO_2e/lb N_2O) = 0.410 lb CO_2e/MMBtu

Total CO2e/MMBtu = 163.05 + 0.139 + 0.410 = <u>163.60 lb CO_2e/MMBtu</u>

Converted to g/hp-hr:

(163.60 lb/MMBtu)(453.6 g/lb)(7500 Btu/hp-hr)/1,000,000 = <u>556.58 g/hp-hr as CO_2</u>

10.2 Permit Renewal Fee

Emission fees for Platform Irene based on a cost reimbursement basis pursuant to District Rule 210.

All work performed with respect to implementing the requirements of the Part 70 Operating Permit program are assessed on a cost reimbursement basis pursuant to District Rule 210.

10.3 Equipment List